AUTHENTICATED
U.S. GOVERNMENT
INFORMATION
GPO

FEDERAL REGISTER

Vol. 89 Thursday,
No. 91 May 9, 2024

Pages 39531–40358

OFFICE OF THE FEDERAL REGISTER

The **FEDERAL REGISTER** (ISSN 0097–6326) is published daily, Monday through Friday, except official holidays, by the Office of the Federal Register, National Archives and Records Administration, under the Federal Register Act (44 U.S.C. Ch. 15) and the regulations of the Administrative Committee of the Federal Register (1 CFR Ch. I). The Superintendent of Documents, U.S. Government Publishing Office, is the exclusive distributor of the official edition. Periodicals postage is paid at Washington, DC.

The **FEDERAL REGISTER** provides a uniform system for making available to the public regulations and legal notices issued by Federal agencies. These include Presidential proclamations and Executive Orders, Federal agency documents having general applicability and legal effect, documents required to be published by act of Congress, and other Federal agency documents of public interest.

Documents are on file for public inspection in the Office of the Federal Register the day before they are published, unless the issuing agency requests earlier filing. For a list of documents currently on file for public inspection, see *www.federalregister.gov.*

The seal of the National Archives and Records Administration authenticates the Federal Register as the official serial publication established under the Federal Register Act. Under 44 U.S.C. 1507, the contents of the **Federal Register** shall be judicially noticed.

The **Federal Register** is published in paper and on 24x microfiche. It is also available online at no charge at *www.govinfo.gov*, a service of the U.S. Government Publishing Office.

The online edition of the **Federal Register** is issued under the authority of the Administrative Committee of the Federal Register as the official legal equivalent of the paper and microfiche editions (44 U.S.C. 4101 and 1 CFR 5.10). It is updated by 6:00 a.m. each day the **Federal Register** is published and includes both text and graphics from Volume 1, 1 (March 14, 1936) forward. For more information, contact the GPO Customer Contact Center, U.S. Government Publishing Office. Phone 202-512-1800 or 866-512-1800 (toll free). E-mail, *gpocusthelp.com.*

The annual subscription price for the **Federal Register** paper edition is $860 plus postage, or $929, for a combined **Federal Register, Federal Register** Index and List of CFR Sections Affected (LSA) subscription; the microfiche edition of the **Federal Register** including the **Federal Register** Index and LSA is $330, plus postage. Six month subscriptions are available for one-half the annual rate. The prevailing postal rates will be applied to orders according to the delivery method requested. The price of a single copy of the daily **Federal Register,** including postage, is based on the number of pages: $11 for an issue containing less than 200 pages; $22 for an issue containing 200 to 400 pages; and $33 for an issue containing more than 400 pages. Single issues of the microfiche edition may be purchased for $3 per copy, including postage. Remit check or money order, made payable to the Superintendent of Documents, or charge to your GPO Deposit Account, VISA, MasterCard, American Express, or Discover. Mail to: U.S. Government Publishing Office—New Orders, P.O. Box 979050, St. Louis, MO 63197-9000; or call toll free 1-866-512-1800, DC area 202-512-1800; or go to the U.S. Government Online Bookstore site, see *bookstore.gpo.gov.*

There are no restrictions on the republication of material appearing in the **Federal Register.**

How To Cite This Publication: Use the volume number and the page number. Example: 89 FR 12345.

Postmaster: Send address changes to the Superintendent of Documents, Federal Register, U.S. Government Publishing Office, Washington, DC 20402, along with the entire mailing label from the last issue received.

SUBSCRIPTIONS AND COPIES

PUBLIC

Subscriptions:

Paper or fiche	**202–09512–1800**
Assistance with public subscriptions	**202–512–1806**
General online information	**202–512–1530; 1–888–293–6498**

Single copies/back copies:

Paper or fiche	**202–512–1800**
Assistance with public single copies	**1–866–512–1800 (Toll-Free)**

FEDERAL AGENCIES

Subscriptions:

Assistance with Federal agency subscriptions:

Email	*FRSubscriptions@nara.gov*
Phone	**202–741–6000**

The Federal Register Printing Savings Act of 2017 (Pub. L. 115-120) placed restrictions on distribution of official printed copies of the daily **Federal Register** to members of Congress and Federal offices. Under this Act, the Director of the Government Publishing Office may not provide printed copies of the daily **Federal Register** unless a Member or other Federal office requests a specific issue or a subscription to the print edition. For more information on how to subscribe use the following website link: *https://www.gpo.gov/frsubs.*

Printed on recycled paper.

Contents

Federal Register

Vol. 89, No. 91

Thursday, May 9, 2024

Agricultural Marketing Service
RULES
Dairy Margin Coverage Production History Adjustment and Program Extension:
Correction, 39539–39540

Agriculture Department
See Agricultural Marketing Service
See Animal and Plant Health Inspection Service
See Commodity Credit Corporation
See Rural Housing Service

Air Force Department
NOTICES
Environmental Impact Statements; Availability, etc.:
492nd Special Operations Wing Beddown at Davis-Monthan Air Force Base, AZ, 39605–39606

Animal and Plant Health Inspection Service
RULES
Use of Electronic Identification Eartags as Official Identification in Cattle and Bison, 39540–39566

Civil Rights Commission
NOTICES
Hearings, Meetings, Proceedings, etc.:
Hawai'i Advisory Committee, 39580–39581

Coast Guard
PROPOSED RULES
Security Zone:
Lake Erie, Mentor (Mentor Headlands), OH, 39576–39578

Commerce Department
See Industry and Security Bureau
See International Trade Administration
See National Oceanic and Atmospheric Administration

Commodity Credit Corporation
NOTICES
Funds Availability:
Organic Certification Cost Share Program, 39579–39580

Community Living Administration
NOTICES
Funding Opportunity:
Program Application Instructions for Medicare Improvements for Patients and Providers Act Program Funds, 39627–39628
Single-Source Supplement:
National Falls Prevention Resource Center, 39628–39629

Corporation for National and Community Service
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Applicant Operational and Financial Survey, 39604–39605

Defense Department
See Air Force Department
See Navy Department
NOTICES
Hearings, Meetings, Proceedings, etc.:
Defense Health Board, 39606–39607

Drug Enforcement Administration
NOTICES
Importer, Manufacturer or Bulk Manufacturer of Controlled Substances; Application, Registration, etc.:
Curia New York, Inc., 39646
Veranova, L.P., 39647

Employment and Training Administration
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Characteristics of the Insured Unemployed, 39649–39650
Unemployment Insurance Title XII Advances and Voluntary Repayment Process, 39648–39649
Allotments:
Program Year 2024 Workforce Innovation and Opportunity Act Title I Allotments; 2024 Title III Wagner-Peyser Act Employment Service Allotments and P2024 Workforce Information Grants, 39650–39658

Energy Department
See Federal Energy Regulatory Commission

Environmental Protection Agency
RULES
New Source Performance Standards:
Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel–Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel–Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 39798–40064
Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 40198–40306
NOTICES
Hearings, Meetings, Proceedings, etc.:
Good Neighbor Environmental Board, 39611
Permits; Applications, Issuances, etc.:
Idaho's Research, Development and Demonstration Permit Provisions for Municipal Solid Waste Landfills; Determination of Adequacy, 39611–39612
Requests for Nominations:
Historically Black Colleges and Universities and Minority Serving Institutions Advisory Council, 39610–39611

Federal Aviation Administration
RULES
Special The Boeing Model 737–8 Airplane; Dynamic Test Requirements for Single-Occupant Oblique Seats With 3-Point Seat Belt With Pretensioner Conditions:, 39566–39569

Federal Communications Commission
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals, 39612–39613

Federal Election Commission
NOTICES
Meetings; Sunshine Act, 39613

Federal Energy Regulatory Commission
NOTICES
Combined Filings, 39608–39610

Federal Highway Administration
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals, 39678–39680

Federal Maritime Commission
RULES
Demurrage and Detention Billing Requirements; Correction, 39569–39570

Federal Motor Carrier Safety Administration
NOTICES
Commercial Driver's License Standards:
Application for Exemption; Pitt Ohio Express, LLC, 39680–39681

Federal Railroad Administration
NOTICES
Petition for Extension of Waiver of Compliance, 39681–39683
Petition for Waiver of Compliance, 39681

Federal Reserve System
NOTICES
Expansion of Fedwire Funds Service and National Settlement Service Operating Hours, 39613–39621
Formations of, Acquisitions by, and Mergers of Bank Holding Companies, 39613

Fish and Wildlife Service
NOTICES
Privacy Act; Systems of Records, 39632–39633

Foreign Assets Control Office
NOTICES
Sanctions Actions, 39683

General Services Administration
NOTICES
Privacy Act; Systems of Records, 39621–39627

Health and Human Services Department
See Community Living Administration
See National Institutes of Health
RULES
Nondiscrimination on the Basis of Disability in Programs or Activities Receiving Federal Financial Assistance, 40066–40195

Homeland Security Department
See Coast Guard

Indian Affairs Bureau
NOTICES
Helping Expedite and Advance Responsible Tribal Homeownership Act:
Approval of Confederated Tribes of the Warm Springs Reservation of Oregon Amended Business Leasing Ordinance, 39635–39636
Approval of Nisqually Indian Tribe Residential Leasing Ordinance, 39634–39635

Industry and Security Bureau
NOTICES
Hearings, Meetings, Proceedings, etc.:
Emerging Technology Technical Advisory Committee, 39581–39582

Institute of Museum and Library Services
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals:
2025–2027 National Leadership Grants for Libraries and Laura Bush 21st Century Librarian, 39660

Interior Department
See Fish and Wildlife Service
See Indian Affairs Bureau
See Land Management Bureau
See National Park Service

Internal Revenue Service
NOTICES
Hearings, Meetings, Proceedings, etc.:
Electronic Tax Administration Advisory Committee, 39683

International Trade Administration
NOTICES
Antidumping or Countervailing Duty Investigations, Orders, or Reviews:
Certain Hot-Rolled Steel Flat Products From Japan, 39584–39586
Certain Paper Shopping Bags From the Republic of Turkiye, 39586–39588
Hydrofluorocarbon Blends From the People's Republic of China, 39582–39584
Quarterly Update to Annual Listing of Foreign Government Subsidies on Articles of Cheese Subject to an In-Quota Rate of Duty, 39588–39589

International Trade Commission
NOTICES
Meetings; Sunshine Act, 39646

Justice Department
See Drug Enforcement Administration

Labor Department
See Employment and Training Administration
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Excavations (Design of Cave-In Protection Systems), 39659
Requirements of a Bona Fide Thrift or Savings Plan and Requirements of a Bona Fide Profit-Sharing Plan or Trust, 39658–39659

Land Management Bureau
RULES
Conservation and Landscape Health, 40308–40349
NOTICES
New Recreation Fees:
Public Lands in Humboldt, Trinity, and Shasta Counties, CA, 39636–39637
Privacy Act; Systems of Records, 39637–39640

National Aeronautics and Space Administration
NOTICES
Environmental Impact Statements; Availability, etc.:
Pacific Missile Range Facility and Koke'e Park Geophysical Observatory Real Estate, 39607–39608

National Credit Union Administration
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals, 39659–39660

National Foundation on the Arts and the Humanities
See Institute of Museum and Library Services

National Highway Traffic Safety Administration
RULES
Federal Motor Vehicle Safety Standards:
Automatic Emergency Braking Systems for Light Vehicles, 39686–39795

National Institutes of Health
NOTICES
Development of the Fiscal Years 2026–2030 Strategic Plan for Sexual and Gender Minority Health Research, 39631–39632
Hearings, Meetings, Proceedings, etc.:
National Institute of Neurological Disorders and Stroke, 39629
Proposed Reorganization:
Division of Program Coordination, Planning, and Strategic Initiatives, Office of the Director, 39630
Request for Information:
Inviting Input Regarding National Institute on Deafness and Other Communication Disorders's Research Directions in Global Health, 39630–39631
Significant Changes to the Grants Policy Statement for Fiscal Year 2024, 39629–39630

National Oceanic and Atmospheric Administration
RULES
Fisheries of the Exclusive Economic Zone off Alaska:
Pacific Cod by Vessels Using Jig Gear in the Central Regulatory Area of the Gulf of Alaska, 39575
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Application for Appointment in the NOAA Commissioned Officer Corps, 39590–39591
Southeast Region Vessel and Gear Identification Requirements, 39589–39590
Taking or Importing of Marine Mammals:
Sitka Seaplane Base Construction, 39591–39604

National Park Service
NOTICES
Intended Disposition:
Arizona Army National Guard, Papago Park Miliary Reservation, Phoenix, AZ, 39642–39643
Inventory Completion:
California State University, Sacramento, Sacramento, CA, 39645–39646
Peabody Museum of Archaeology and Ethnology, Harvard University, Cambridge, MA, 39643–39645
Repatriation of Cultural Items:
California State University, Sacramento, Sacramento, CA, 39640–39641
Gilcrease Museum, Tulsa, OK, 39642, 39644
Oakland Museum of California, Oakland, CA, 39641–39642

National Science Foundation
NOTICES
Hearings, Meetings, Proceedings, etc.:
Advisory Committee for Social, Behavioral and Economic Sciences, 39661–39662
Astronomy and Astrophysics Advisory Committee, 39661
Committee on Equal Opportunities in Science and Engineering, 39660–39661

Navy Department
NOTICES
Environmental Impact Statements; Availability, etc.:
Pacific Missile Range Facility and Koke'e Park Geophysical Observatory Real Estate, 39607–39608

Nuclear Regulatory Commission
NOTICES
Environmental Assessments; Availability, etc.:
Global Laser Enrichment, LLC, 39662–39663

Pension Benefit Guaranty Corporation
NOTICES
Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Mergers and Transfers Between Multiemployer Plans, 39663–39664

Pipeline and Hazardous Materials Safety Administration
RULES
Hazardous Materials:
Harmonization With International Standards; Correction, 39570–39575

Postal Regulatory Commission
NOTICES
New Postal Products, 39664–39665

Postal Service
NOTICES
Product Change:
Priority Mail and USPS Ground Advantage Negotiated Service Agreement, 39665–39668
Priority Mail Express Negotiated Service Agreement, 39667–39668
Priority Mail Express, Priority Mail, USPS Ground Advantage, and Parcel Select Negotiated Service Agreement, 39665–39666

Presidential Documents
PROCLAMATIONS
Berryessa Snow Mountain National Monument; Boundary Enlargement (Proc. 10745), 39531–39537
ADMINISTRATIVE ORDERS
Central African Republic; Continuation of National Emergency (Notice of May 8, 2024), 40357
Information and Communications Technology and Services, Supply Chain Security; Continuation of National Emergency (Notice of May 8, 2024), 40351–40353
Syria; Continuation of National Emergency (Notice of May 8, 2024), 40355–40356

Rural Housing Service
NOTICES
Request for Application:
Off-Farm Labor Housing Loans and Off-Farm Labor Housing Grants for New Construction for Fiscal Year 2024; Correction, 39580

Securities and Exchange Commission
NOTICES
Self-Regulatory Organizations; Proposed Rule Changes:
Nasdaq BX, Inc., 39674–39677
Nasdaq PHLX LLC, 39668–39674

Small Business Administration
NOTICES
Disaster or Emergency Declaration and Related Determination:
Louisiana, 39677
Maryland; Correction, 39677–39678

State Department
NOTICES
Sanctions Actions, 39678

State Justice Institute
NOTICES
Hearings, Meetings, Proceedings, etc.:
Board of Directors, 39678

Transportation Department
See Federal Aviation Administration
See Federal Highway Administration
See Federal Motor Carrier Safety Administration
See Federal Railroad Administration
See National Highway Traffic Safety Administration
See Pipeline and Hazardous Materials Safety Administration

Treasury Department
See Foreign Assets Control Office
See Internal Revenue Service

U.S. International Development Finance Corporation
NOTICES
Hearings, Meetings, Proceedings, etc., 39605

Separate Parts In This Issue

Part II
Transportation Department, National Highway Traffic Safety Administration, 39686–39795

Part III
Environmental Protection Agency, 39798–40064

Part IV
Health and Human Services Department, 40066–40195

Part V
Environmental Protection Agency, 40198–40306

Part VI
Interior Department, Land Management Bureau, 40308–40349

Part VII
Presidential Documents, 40351–40353, 40355–40357

Reader Aids
Consult the Reader Aids section at the end of this issue for phone numbers, online resources, finding aids, and notice of recently enacted public laws.

To subscribe to the Federal Register Table of Contents electronic mailing list, go to https://public.govdelivery.com/accounts/USGPOOFR/subscriber/new, enter your e-mail address, then follow the instructions to join, leave, or manage your subscription.

CFR PARTS AFFECTED IN THIS ISSUE

A cumulative list of the parts affected this month can be found in the Reader Aids section at the end of this issue.

3 CFR

Proclamations:
10745.....39531

Administrative Orders:
Notices:
Notice of May 8, 2024.....40353
Notice of May 8, 2024.....40355
Notice of May 8, 2024.....40357

7 CFR
1430.....39539

9 CFR
71.....39540
77.....39540
78.....39540
86.....39540

14 CFR
25.....39566

33 CFR

Proposed Rules:
165.....39576

40 CFR
60.....39798
423.....40198

43 CFR
1600.....40308
6100.....40308

45 CFR
84.....40066

46 CFR
541.....39561

49 CFR
171.....39570
172.....39570
173.....39570
175.....39570
176.....39570
178.....39570
180.....39570
571.....39686
595.....39686
596.....39686

50 CFR
679.....39575

Federal Register
Vol. 89, No. 91
Thursday, May 9, 2024

Presidential Documents

Title 3—

The President

Proclamation 10745 of May 2, 2024

Boundary Enlargement of the Berryessa Snow Mountain National Monument

By the President of the United States of America

A Proclamation

Through Proclamation 9298 of July 10, 2015, President Obama established the Berryessa Snow Mountain National Monument (monument) to protect an array of spectacular historic, cultural, geologic, and ecological resources in the heart of northern California's Inner Coast Range. Straddling the eastern edge of the monument boundary, Molok Luyuk—which means ''Condor Ridge'' in the language of the Patwin people—is a striking 11-mile north-to-south ridgeline that is sacred to the Patwin people and contains a mosaic of historic objects and rare natural communities supported by the unique geologic and hydrologic features of the area. The ridgeline, also known as Walker Ridge, is flanked by chaparral-covered canyons, serpentinite outcroppings, oak and cypress woodlands, and spring-fed meadows. Lands within the Molok Luyuk area show evidence of occupation by Indigenous peoples for more than 10,000 years. The historical significance of Molok Luyuk contributes to its cultural and spiritual significance to the Patwin people, and many other Indigenous peoples from northern California also have ties to the area, including the Pomo, Lake Miwok, Yuki, and Nomlaki. While much of the western slope of the ridge was designated as part of the monument by Proclamation 9298, expanding the monument's eastern boundary to include the full Molok Luyuk area—from the ridgeline to the point where the foothills recede into the flatlands of Bear Valley—will protect additional objects of scientific and historic interest and enable holistic management of a culturally significant landscape.

Since time immemorial, Molok Luyuk has held a deep cultural significance for Tribal Nations of the Patwin people, including the Yocha Dehe Wintun Nation, the Kletsel Dehe Band of Wintun Indians, and the Cachil Dehe Band of Wintun Indians. Their history is connected to Molok Luyuk and their lifeways are intertwined with the features, plants, and wildlife of the expansion area. The name Molok Luyuk recalls a time when condors were a common sight soaring above the ridge, and the Patwin people would often celebrate them with dances and ceremonies. On a clear day, the highest points of Molok Luyuk offer a commanding view of the surrounding rugged and undeveloped landscape, encompassing Mount Shasta to the north, Mount Tamalpais to the southwest, and Sutter Buttes to the east. This viewshed, and particularly the view of the sun rising over Sutter Buttes, is central to the Patwin origin story and connected the Patwin communities that once lived in the hills of Molok Luyuk and beyond with the River Patwin communities that populated Bear Valley, which lies just to the east, before they were displaced by trappers, ranchers, and miners. The expansion area includes sites of historic and ceremonial importance to members of all three Patwin Nations along the ridgeline and around its numerous natural springs.

The area around Molok Luyuk has long contained numerous objects of scientific and historic interest. Molok Luyuk played an important role in providing for the sustenance of the Patwin communities that were once found in the area. Occupants of nearby villages made seasonal forays to the ridge and flanks of Molok Luyuk in search of manzanita berries, clover,

gray pine nuts, acorns, bulbs, and tubers, as well as to hunt elk and deer. Evidence of this cultural story marks the landscape today through numerous lithic scatters—sites containing ancient tools, tool fragments, and lithic flakes from tool production and maintenance—found along Molok Luyuk and around the area's cold springs. These scatter sites, which in some cases date back thousands of years, likely represent hunting and gathering camps and sites used by generations of Indigenous people for ceremonial purposes. Artifacts from these sites include obsidian tools made from sources in the region.

Trails once crossed and stretched out from the ridgeline. These trails, which ran atop the ridge and just inside the northern and southern boundaries of the expansion area, are important to the history of how Patwin communities were connected to other Indigenous communities in northern California. For instance, they enabled cultural exchanges among Indigenous people in the region, connected villages, and facilitated access to seasonal camps and ceremonial sites. Knowledge of the trails lives within Patwin oral history and cultural expertise and has been documented in ethnographic studies. Some trails were part of a larger interregional network by which other northern California Indigenous peoples would access Molok Luyuk and the healing hot springs that today lie on private land just to the south of the expansion area.

A tumultuous geologic history underpins the expansion area's diverse ecological communities. The backbone of Molok Luyuk is an ophiolite formed by unusual ultramafic rocks. Serpentinite, as this rock is more commonly known, was originally formed deep within the Earth's mantle and eventually thrust upward through the forces of plate tectonics. The landscape is subtly marked by the smoky gray-green of serpentine rocks and their derivative soils. Rare serpentine soils resulting from eroded serpentinite dominate the ridgeline and eastern flank of Molok Luyuk. These soils have unusually high levels of magnesium and iron and very low levels of nutrients, such as calcium and phosphorus, that are critical for the survival of most plants. This soil chemistry imposed evolutionary pressure resulting in a profusion of unique species and habitats that are inhospitable to non-native species that may dominate elsewhere.

Protecting serpentine soils like those found in the expansion area is essential to the preservation of California's endemic and rare plant life. While serpentine soils occur on less than 1.5 percent of California's land base, they are home to nearly 15 percent of California endemic species and nearly 11 percent of its rare plant taxa. Consistent with this State-wide data, the great majority of special-status plant taxa within the Molok Luyuk area occur primarily on serpentine soils.

Molok Luyuk's diverse topography and geology, which also include sandstone and shale, create the conditions for its 13 distinct plant communities, 9 of which spring from serpentine soils. These habitats include serpentine and non-serpentine chaparral, McNab and Sargent cypress and blue and live oak woodlands, serpentine riparian woodland, native wildflower fields, and serpentine seeps. This diversity of plants and plant communities provided the wide array of foods, tools, and medicines that the Patwin gathered from Molok Luyuk. Nearly 500 native California plant taxa have been identified within the expansion area, including at least 38 different special-status plant taxa. The expansion area also includes suitable habitat for another 30 special-status plants that have been documented in the surrounding area. Numerous studies—particularly those focused on species that grow on serpentine soils—have made use of botanical samples from the expansion area, and protecting these rare and sensitive plants will preserve opportunities for important future botanical research.

Brilliant fields of native wildflowers and bunchgrasses are scattered throughout Molok Luyuk. Springtime brings a kaleidoscopic display of butter-yellow golden fairy lantern, flame-like woolly Indian paintbrush, and brilliant orange starbursts of flame ragwort, all of which are native species that thrive in

the area's serpentine meadows. The delicate violet flowers of the Indian Valley brodiaea, a bulbiferous perennial herb that is listed as a State of California endangered species, can also be found tucked into serpentine seeps. Throughout the summer, the small white flowers of the drymary dwarf flax, a Bureau of Land Management (BLM) sensitive species that is endemic to California, are widespread on Molok Luyuk's higher elevation serpentine slopes.

Unusual serpentine wetlands occur along Molok Luyuk, as well as on downslope benches and along Highway 20 near the Colusa-Lake county line. Many of these wetlands are fed by the numerous seeps and springs scattered across the area, which are of critical importance to the area's botanical richness. These include Barrel Springs in the northeastern portion of the expansion area, Cold Spring near the center of the ridgeline, and Til Jones and Eaton Springs in the south, along with numerous other unnamed springs. Protecting these springs, and the wetlands they feed, is critical to preserving the rare and endemic species that thrive within the monument and expansion area—and to preserving opportunities for future scientific study.

Despite substantial fragmentation due to fires in 2008 and 2018, McNab cypress woodland, a California-designated sensitive natural community that is vulnerable at both the global and State scales, dominates portions of the northern, higher elevations. In addition to being a rare and vulnerable natural community of scientific interest, the McNab cypress, for which these woodlands are named, have been used for Patwin ceremonies and medicines for generations and continue to be used today.

A wide variety of mammals, birds, reptiles, and amphibians use or make their homes in Molok Luyuk. More than 80 species of birds have been recorded in the area, including 18 special-status species. Both bald and golden eagles can be observed gliding through the sky above Molok Luyuk. Foothill yellow-legged frogs, a BLM sensitive species, can be found in lower-elevation streams within the expansion area. Members of the oldest free-ranging tule elk herd in California also reside within the expansion area. Tule elk, which are endemic to California, had vanished from the wild until a formerly captive herd was released in 1922 in Colusa County. Other wildlife species that make their homes in Molok Luyuk include black-tail deer, black bear, coyote, bobcat, gopher snake, and western rattlesnake. The slopes of Molok Luyuk provide an avenue for wildlife to move from the lower elevations of Bear Valley to the higher elevation of the ridgeline. Conserving this expansion area will fortify protection for the critical north-south migration corridor provided by the existing monument.

As night falls over Molok Luyuk, other residents of the area emerge. At least 14 species of bats occur in the area, including the western red bat, pallid bat, and Townsend's big-eared bat, each of which is a California Species of Special Concern. The night skies through which they fly are remarkably unmarred by light pollution, which can disturb many species of bats as well as other mammals and birds, and provide increasingly rare and extraordinary stargazing opportunities to those who venture out after sunset.

In light of threats, including impacts from climate change, increased recreational use, and development potential, expanding the boundaries of the Berryessa Snow Mountain National Monument to protect the area described above will preserve a diverse array of natural and scientific resources and cultural and historic legacy sites, ensuring that the scientific and historic values of this area endure for the benefit of all Americans. The expansion area contains numerous objects of historic and scientific interest, and it also provides opportunities for those who seek out places of beauty and botanical wonder, whether through hiking, hunting, scenic driving, camping, wildflower viewing, or lying under a vast expanse of undimmed starry sky.

WHEREAS, section 320301 of title 54, United States Code (the ''Antiquities Act''), authorizes the President, in his discretion, to declare by public proclamation historic landmarks, historic and prehistoric structures, and other objects of historic or scientific interest that are situated upon the lands owned or controlled by the Federal Government to be national monuments, and to reserve as a part thereof parcels of land, the limits of which shall be confined to the smallest area compatible with the proper care and management of the objects to be protected; and

WHEREAS, I find that each of the objects identified above, and objects of the type identified above within the area described herein, are objects of historic or scientific interest in need of protection under section 320301 of title 54, United States Code, regardless of whether they are expressly identified as an object of historic or scientific interest in the text of this proclamation; and

WHEREAS, I find that there are threats to the objects identified in this proclamation, and in the absence of a reservation under the Antiquities Act, the objects identified in this proclamation are not adequately protected by applicable law or administrative designations, thus making a national monument designation and reservation necessary to protect the objects of historic and scientific interest identified above for current and future generations; and

WHEREAS, I find that the boundaries of the monument reserved by this proclamation represent the smallest area compatible with the proper care and management of the objects of scientific or historic interest identified above, as required by the Antiquities Act; and

WHEREAS, it is in the public interest to ensure the preservation, restoration, and protection of the objects of scientific and historic interest identified above;

NOW, THEREFORE, I, JOSEPH R. BIDEN JR., President of the United States of America, by the authority vested in me by section 320301 of title 54, United States Code, hereby proclaim the objects identified above that are situated upon lands and interests in lands owned or controlled by the Federal Government to be part of the Berryessa Snow Mountain National Monument and, for the purpose of protecting those objects, reserve as part thereof all lands and interests in lands that are owned or controlled by the Federal Government within the boundaries described on the accompanying map, which is attached hereto and forms a part of this proclamation. The reserved Federal lands and interests in lands within the expansion area encompass approximately 13,696 acres. As a result of the distribution of the objects throughout the area, the boundaries described on the accompanying map are confined to the smallest area compatible with the proper care and management of the objects of historic or scientific interest identified above.

Nothing in this proclamation shall change the management of the areas protected under Proclamation 9298. The terms, conditions, and management direction provided by Proclamation 9298, including any term limiting the construction or effect of Proclamation 9298, are incorporated by reference and shall apply to the area reserved by this proclamation except to the extent that they are inconsistent with a provision in this proclamation.

All Federal lands and interests in lands described on the accompanying map are hereby appropriated and withdrawn from all forms of entry, location, selection, sale, or other disposition under the public land laws; from location, entry, and patent under the mining laws; and from disposition under all laws relating to mineral and geothermal leasing, other than by exchange that facilitates the remediation, monitoring, or reclamation of historic mining operations under applicable law or otherwise furthers the protective purposes of the monument.

The enlargement of the boundary is subject to valid existing rights. If the Federal Government subsequently acquires any lands or interests in lands

not currently owned or controlled by the Federal Government within the boundaries described on the accompanying map, such lands and interests in lands shall be reserved as a part of the monument, and objects of the type identified above that are situated upon those lands and interests in lands shall be part of the monument, upon acquisition of ownership or control by the Federal Government.

The Secretary of the Interior (Secretary), through the BLM, shall manage the expansion area pursuant to applicable legal authorities, as a unit of the National Landscape Conservation System, and in accordance with the terms, conditions, and management direction provided by this proclamation and, as described above, those provided by Proclamation 9298.

For purposes of protecting and restoring the objects identified above, the Secretary shall include the lands within the expansion area in the management plan for the monument provided for in Proclamation 9298. The Secretary shall promulgate such rules and regulations for the management of the expansion area as deemed appropriate.

Consistent with the direction in Proclamation 9298, in recognition of the importance of Tribal participation in the care and management of the objects identified above, and to ensure that management decisions are informed by and reflect Tribal expertise and Indigenous Knowledge, the Secretary shall explore entering into one or more memoranda of understanding with interested Tribal Nations to set forth terms, pursuant to applicable laws, regulations, and policies, for co-stewardship of the expansion area, as well as for educational and other outreach efforts regarding the history of the Tribal Nations in the area and the name Molok Luyuk.

In order to reflect the historic, spiritual, and cultural significance of Molok Luyuk to the Patwin Tribes as discussed throughout this proclamation, the geographic feature identified in the Federal Geographic Names Information System as Feature 237183 shall be renamed Molok Luyuk. The Secretary and the Board of Geographic Names shall take any necessary and appropriate steps to make this change in the Geographic Names Information System. Except as necessary for the care and management of the objects identified above, no new rights-of-way shall be authorized within the area reserved by this proclamation.

The Secretary shall issue a travel management plan that authorizes motorized and non-motorized mechanized vehicle use, including mountain biking, so long as such use is consistent with the care and management of the objects identified above. Further, the Secretary shall monitor motorized and non-motorized mechanized vehicle use and designated roads and trails to ensure proper care and management of the objects identified above.

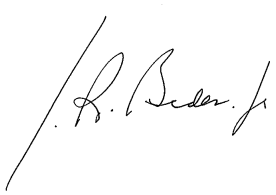
The Secretary shall evaluate opportunities to enter into one or more agreements with governments, including State, local, and Tribal, regarding protection of the objects identified above during wildland fire prevention and response efforts.

If any provision of this proclamation, including its application to a particular parcel of land, is held to be invalid, the remainder of this proclamation and its application to other parcels of land shall not be affected thereby.

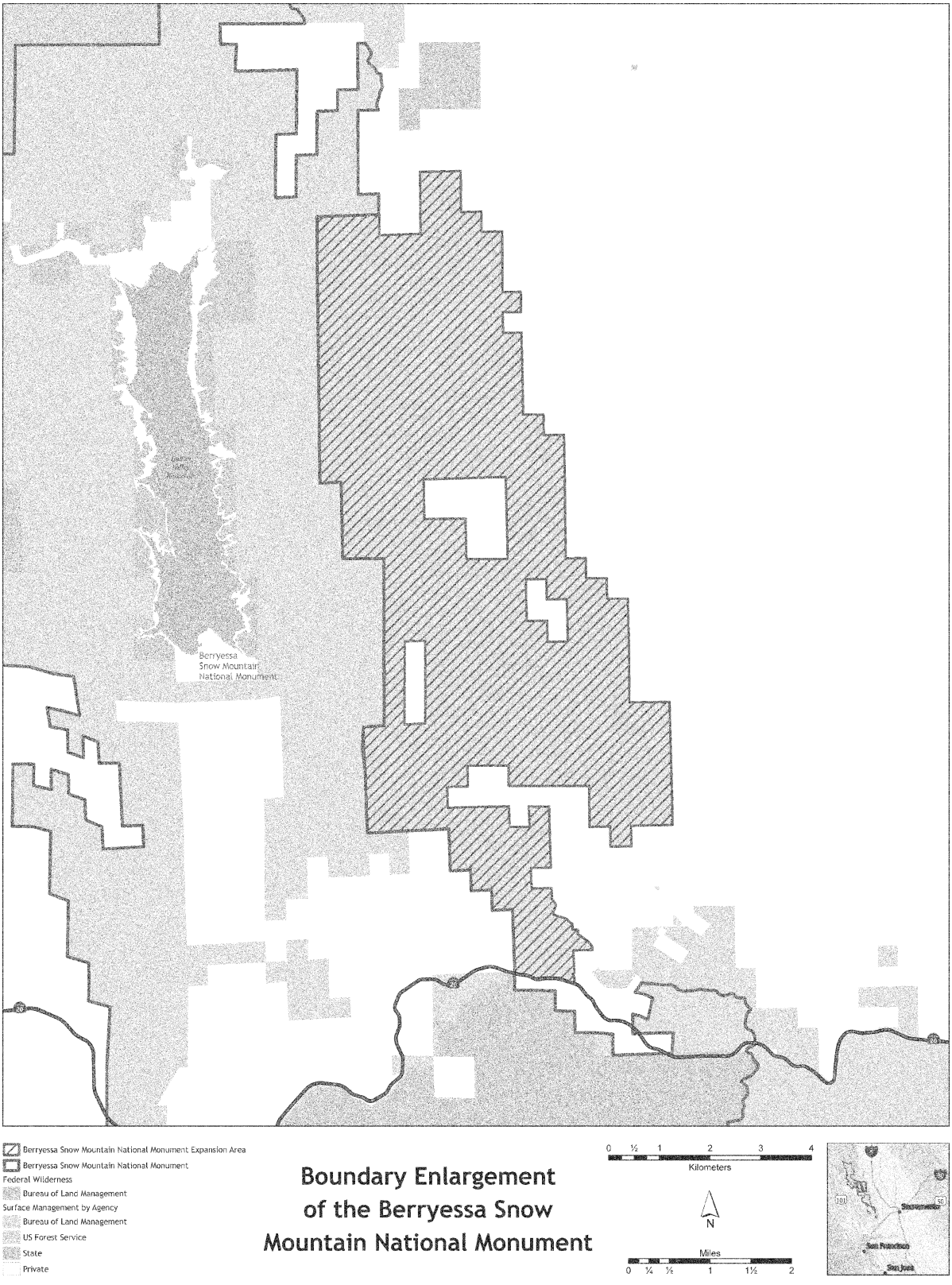
Nothing in this proclamation shall be deemed to revoke any existing withdrawal, reservation, or appropriation; however, the monument shall be the dominant reservation.

Warning is hereby given to all unauthorized persons not to appropriate, injure, destroy, or remove any feature of the monument and not to locate or settle upon any of the lands thereof.

IN WITNESS WHEREOF, I have hereunto set my hand this second day of May, in the year of our Lord two thousand twenty-four, and of the Independence of the United States of America the two hundred and forty-eighth.



Billing code 3395–F4–P



[FR Doc. 2024–10266

Filed 5–8–24; 8:45 am]

Billing code 4310–10–C

Rules and Regulations

Federal Register
Vol. 89, No. 91
Thursday, May 9, 2024

This section of the FEDERAL REGISTER contains regulatory documents having general applicability and legal effect, most of which are keyed to and codified in the Code of Federal Regulations, which is published under 50 titles pursuant to 44 U.S.C. 1510.

The Code of Federal Regulations is sold by the Superintendent of Documents.

DEPARTMENT OF AGRICULTURE

Commodity Credit Corporation

7 CFR Part 1430

RIN 0560–AI66

[Docket No. FSA–2024–0001]

Dairy Margin Coverage Production History Adjustment and Program Extension; Correction

AGENCY: Commodity Credit Corporation (CCC) and Farm Service Agency (FSA), Department of Agriculture (USDA).

ACTION: Final rule; technical correction.

SUMMARY: CCC and FSA are making a technical correction to the Dairy Margin Coverage (DMC) regulations published on February 27, 2024. The technical correction will apply to the 2024 DMC coverage election period to allow dairy operations that dissolved prior to or during the 2024 DMC coverage election period the opportunity to enroll in 2024 DMC for the days they marketed milk in the 2024 calendar year.

DATES:

Effective: May 9, 2024.

Application deadline for dissolved dairies to apply for DMC: May 23, 2024.

FOR FURTHER INFORMATION CONTACT: Douglas Kilgore; telephone: (717) 887–0963; email: *douglas.e.kilgore@usda.gov.* Individuals who require alternative means of communication should contact the USDA TARGET Center at (202) 720–2600 (voice and text telephone (TTY)) or dial 711 for Telecommunications Relay Service (both voice and text telephone users can initiate this call from any telephone).

SUPPLEMENTARY INFORMATION:

Correction

FSA announced changes made to DMC in a final rule on February 27, 2024 (89 FR 14372–14376). FSA inadvertently omitted a modification in 7 CFR 1430.403 to allow dairy operations that dissolved in the 2024 calendar year prior to or during the 2024 DMC coverage election period, the opportunity to enroll in 2024 DMC for the days the dairy operations were still in business and commercially marketing milk.

This technical correction amends the DMC regulation in 7 CFR 1430.403(a)(1) by inserting ''and 2024'' to address the unintentional exclusion of dairy operations that dissolved and stopped commercially marketing milk in the 2024 calendar year at any time before or during the DMC 2024 enrollment period that began on February 2, 2024, and ends on April 29, 2024.

Under the February 27, 2024, final rule, to be approved for enrollment in DMC, participating dairy operations must certify that they are commercially marketing milk at the time of application for DMC. Most DMC annual enrollment periods occur before the start of the coverage year. However, DMC changes authorized by the Further Continuing Appropriations and Other Extensions Act, 2024 (Pub. L. 118–22) required that a regulatory amendment to DMC be published before the coverage election period for 2024 could begin. As a result, some dairy operations that were marketing milk early in 2024, but then dissolved, were not eligible for 2024 DMC for the days they marketed milk in 2024.

The technical correction to the rule is consistent with how dissolved dairy operations were treated during coverage election periods that did not begin before the start of the applicable DMC coverage year in the past. For example, in 2019, when the 2019 DMC coverage election period was delayed until mid-year, provisions were provided in the rule to allow dairy operations that dissolved in the 2019 calendar year prior to or during the 2019 coverage election period the opportunity to enroll in 2019 DMC and receive benefits for the days they were commercially marketing milk. This technical correction provides dissolved dairy operations the opportunity to enroll in 2024 DMC under provisions consistent with 2019 DMC implementation. This is also consistent with the Congressional intention that DMC be available to eligible dairy operations as of the start of the 2024 calendar year, as illustrated by section 102(g) of Title I of Division B of the Further Continuing Appropriations and Other Extensions Act, 2024, which provides for the extension of DMC, among other provisions, to be effective as of September 30, 2023.

To enroll, you must send your application for 2024 DMC to the administrative county FSA office serving the dairy operation. Participating dairy operations that dissolved in the 2024 calendar year prior to or during the 2024 DMC coverage election period may apply for DMC. The deadline for dissolved dairies to apply for DMC is May 23, 2024. This application is to enroll in 2024 DMC for the days the dissolved dairy operation was still in business and commercially marketing milk.

USDA Non-Discrimination Policy

In accordance with Federal civil rights law and USDA civil rights regulations and policies, USDA, its Agencies, offices, and employees, and institutions participating in or administering USDA programs are prohibited from discriminating based on race, color, national origin, religion, sex, gender identity (including gender expression), sexual orientation, disability, age, marital status, family or parental status, income derived from a public assistance program, political beliefs, or reprisal or retaliation for prior civil rights activity, in any program or activity conducted or funded by USDA (not all bases apply to all programs). Remedies and complaint filing deadlines vary by program or incident.

Individuals who require alternative means of communication for program information (for example, braille, large print, audiotape, American Sign Language, etc.) should contact the responsible Agency or USDA TARGET Center at (202) 720–2600 (voice and text telephone (TTY)) or dial 711 for Telecommunications Relay Service (both voice and text telephone users can initiate this call from any telephone). Additionally, program information may be made available in languages other than English.

To file a program discrimination complaint, complete the USDA Program Discrimination Complaint Form, AD–3027, found online at *https://www.usda.gov/oascr/how-to-file-a-program-discrimination-complaint* and at any USDA office or write a letter addressed to USDA and provide in the letter all the information requested in the form. To request a copy of the

complaint form, call (866) 632–9992. Submit your completed form or letter to USDA by: (1) mail to: U.S. Department of Agriculture, Office of the Assistant Secretary for Civil Rights, 1400 Independence Avenue SW, Washington, DC 20250–9410; (2) fax: (202) 690–7442; or (3) email: *program.intake@usda.gov.*

USDA is an equal opportunity provider, employer, and lender.

List of Subjects in 7 CFR Part 1430

Dairy products, Fraud, Penalties, Price support programs, Reporting and recordkeeping requirements.

For the reasons discussed above, CCC amends 7 CFR part 1430 as follows:

PART 1430—DAIRY PRODUCTS

■ 1. The authority citation for part 1430 continues to read as follows:

Authority: 7 U.S.C. 9051–9060 and 9071 and 15 U.S.C. 714b and 714c.

Subpart D—Dairy Margin Coverage Program

§ 1430.403 [Amended]

■ 2. In § 1430.403, amend paragraph (a)(1) by removing the year ''2019'' and adding ''2019 and 2024'' in its place.

Zach Ducheneaux,

Administrator, Farm Service Agency, and Executive Vice President, Commodity Credit Corporation.

[FR Doc. 2024–10162 Filed 5–8–24; 8:45 am]

BILLING CODE 3410–E2–P

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

9 CFR Parts 71, 77, 78, and 86

[Docket No. APHIS–2021–0020]

RIN 0579–AE64

Use of Electronic Identification Eartags as Official Identification in Cattle and Bison

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Final rule.

SUMMARY: We are amending the animal disease traceability regulations to require that eartags applied on or after a date 180 days after publication in the **Federal Register** of this final rule be both visually and electronically readable in order to be recognized for use as official eartags for interstate movement of cattle and bison covered under the regulations. We are also clarifying certain record retention and record access requirements and revising some requirements pertaining to slaughter cattle. These changes will enhance the ability of Tribal, State and Federal officials, private veterinarians, and livestock producers to quickly respond to high-impact diseases currently existing in the United States, as well as foreign animal diseases that threaten the viability of the U.S. cattle and bison industries.

DATES: This rule is effective November 5, 2024.

FOR FURTHER INFORMATION CONTACT: Dr. Alexander K. Turner, Acting Director, Animal Disease Traceability and Veterinary Accreditation Center, Strategy and Policy, VS, APHIS, 2150 Centre Ave., Building B, Fort Collins, CO 80526; (970) 494–7353.

SUPPLEMENTARY INFORMATION:

Background

Under the Animal Health Protection Act (AHPA, 7 U.S.C. 8301 *et seq.*), the Secretary of Agriculture has the authority to issue orders and regulations to prevent the introduction into the United States and the dissemination within the United States of any pest or disease of livestock. Within the U.S. Department of Agriculture (USDA), the Animal and Plant Health Inspection Service (APHIS) has primary regulatory responsibility to prevent, control, and eradicate communicable diseases of livestock in the United States. Knowing where diseased and at-risk animals are, where they have been, and when, is indispensable in emergency response and in ongoing disease control and eradication programs.

The animal disease traceability regulations, which were set forth in a final rule [1] published on January 9, 2013 (78 FR 2040–2075, Docket No. APHIS–2009–0091) and are contained in 9 CFR part 86, provide the requirements for identification and documentation for certain classes of cattle and bison to move interstate. These regulations establish minimum national official identification and documentation requirements for the traceability of livestock moving interstate. The species covered in the regulations include cattle and bison (sexually intact and 18 months of age or older, all female dairy cattle of any age and male dairy cattle born after March 11, 2013, cattle and bison of any age used for rodeo or recreational events, and cattle and bison of any age used for shows or exhibitions), sheep and goats, swine, horses and other equids, captive cervids (*e.g.,* deer and elk), and poultry.

Under the regulations, official identification devices or methods are determined by the APHIS Administrator. An ''official identification device or method'' is defined in § 86.1 of the regulations as ''[a] means approved by the Administrator of applying an official identification number to an animal of a specific species or associating an official identification number with an animal or group of animals of a specific species or otherwise officially identifying an animal or group of animals.''

One of the approved identification methods for cattle and bison covered by part 86 is an official eartag. An official eartag is defined in § 86.1 of the regulations as ''[a]n identification tag approved by APHIS that bears an official identification number for individual animals. Beginning March 11, 2014, all official eartags manufactured must bear an official eartag shield. Beginning March 11, 2015, all official eartags applied to animals must bear an official eartag shield. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.'' The other methods of official identification of cattle and bison include ''[b]rands registered with a recognized brand inspection authority and accompanied by an official brand inspection certificate, when agreed to by the shipping and receiving State or Tribal animal health authorities; or [t]attoos and other identification methods acceptable to a breed association for registration purposes, accompanied by a breed registration certificate, when agreed to by the shipping and receiving State or Tribal animal health authorities; or Group/lot identification when a group/lot identification number (GIN) may be used.'' 9 CFR 86.4(a)(1)(ii) through (iv).

Historically, APHIS has used metal, non-electronic identification (EID) tags for animal identification in disease programs for many decades and has approved both non-EID and radio frequency identification (RFID, a form of EID) tags for use as official eartags in cattle and bison since 2008.

Since the enactment of the animal disease traceability regulations, APHIS has worked with stakeholders to enhance its traceability capacity within the Animal Disease Traceability (ADT) program. In January 2017, APHIS staff officers met with State officials and

[1] To view the final rule, supporting documents, and comments we received, go to: *https://www.regulations.gov/docket/APHIS-2009-0091.*

APHIS Veterinary Services field officers to gather input on what was working well in the traceability program and what gaps remained. A report of our findings was published in April 2017 (*https://www.aphis.usda.gov/traceability/downloads/adt-assessment.pdf*). Among other findings, the report discussed gaps in tracing animals due to the challenges of reading and recording numbers from non-EID eartags. A similar gap identified was the need for greater efficiency in collecting Animal Identification Numbers (AINs) or other official identification numbers of individual animals at slaughter and removing those identification numbers from future tracing efforts. Eliminating this gap was determined not to be feasible with visual-only eartags, but could be achieved with EID eartags.

On April 4, 2017, we published in the **Federal Register** (82 FR 16336, Docket No. APHIS–2017–0016) a notice [2] announcing a series of public meetings aimed at soliciting comment on the animal disease traceability program. A total of nine public meetings were hosted by APHIS between April and July of that year, and an additional meeting was hosted by the Kansas Department of Agriculture. As discussed in the April 2017 notice, the purpose of the meetings paralleled the prior discussion with State officials and APHIS field officers: to ''hear from the public about the successes and challenges of the current ADT framework.'' We specifically solicited attendance from cattle and bison industry members, as well as impacted States and Tribes.

The notice and meetings generated 462 written public comments. A working group composed of State and Federal officials, formed in March of 2017 to plan and attend the public meetings, was further tasked with listening to the discussions and preparing a final report summarizing input from the meetings and proposing directions to address gaps in the traceability system. The report was presented at the National Institute for Animal Agriculture fall public forum in September of 2017 and published in April of 2018 (*https://www.aphis.usda.gov/publications/animal_health/adt-summary-program-review.pdf*).

During the remainder of 2017, 2018, and 2019, APHIS personnel frequently met with stakeholders to discuss questions and topics that arose during the 2017 outreach meetings. In addition to individual and industry organization meetings, APHIS officers met with State officials as well as industry stakeholders at national public forums including the United States Animal Health Association and the National Institute for Animal Agriculture forum.

During this period, cattle and bison organizations provided significant and ongoing input on the animal disease traceability program. Although not everyone agreed, many stakeholders commented that electronic records and electronic identification were of significant value and were needed to protect the industry from diseases with potential for high economic impacts.

While APHIS focuses on interstate movement of livestock, States and Tribal Nations remain responsible for the traceability of livestock within their jurisdictions. APHIS partners with State veterinary officials each year to test the performance of States' animal disease traceability systems with regard to the interstate movement of cattle and bison covered under 9 CFR part 86. (Tribes are free to request such test exercises on a voluntary basis and APHIS will report to the Tribes the results of any such exercise. At this time, Tribes have not requested such test exercises.) Results of these test exercises can be viewed on APHIS' traceability web page.[3] The results indicate that when State veterinary officials are provided an identification number from an animal that has been identified with an official identification eartag, whether non-EID (*e.g.,* metal or plastic) or electronic, and the number has been entered accurately into a data system, States on average can trace animals to any one of these four locations in less than 1 hour: the State where an animal was officially identified, the location in-State where an animal was officially identified, the State from which an animal was shipped out of, and the location in-State that an animal was shipped out-of-State from. However, lengthy times or failed traces in the test exercises resulted when numbers from non-EID tags were transcribed inaccurately, movement records were not readily available, or information was only retrievable from labor-intensive paper filing systems. We believe electronic tags and electronic record systems provide a significant advantage over non-EID tags and paper record systems, or systems that involve manual entry of tag numbers, by enabling rapid and accurate reading and recording of tag numbers and retrieval of traceability information.

In support of greater efficiency in traceability and in furtherance of the above-listed program goals, on July 6, 2020, we published in the **Federal Register** (85 FR 40184–40185, Docket No. APHIS–2020–0022) a notice [4] in which we announced our proposal to approve only RFID tags as the official eartag for use in interstate movement of cattle and bison that are covered under the regulations. Specifically, the notice proposed that:

- Beginning January 1, 2022, USDA would no longer approve vendors to use the official USDA shield in production of visual eartags or other eartags that do not have RFID components.
- On January 1, 2023, RFID tags would become the only identification devices approved as an official eartag for cattle and bison pursuant to § 86.4(a)(1)(i).
- For cattle and bison that have official USDA visual (metal) tags in place before January 1, 2023, APHIS would recognize the visual (metal) tag as an official identification device for the life of the animal.

The 2020 notice further clarified that we were proposing no changes to the regulations pertaining to, nor proposing to restrict the use of, other official identification methods authorized by 9 CFR 86.4(a)(1)(ii) through (iv) (such as the use of tattoos and brands when accepted by State veterinary officials in the sending and receiving States).

We solicited comments on the 2020 notice for 90 days ending on October 5, 2020. We received 935 comments by that date from industry groups, producers, veterinarians, State departments of agriculture, and individuals.

Many of the commenters representing industry organizations and State department of agriculture regulatory officials were supportive of the transition and agreed with APHIS that RFID allowed for greater efficiency than non-electronic means of identification and furthered the goals of the ADT program with regard to animal traceability. We also received many comments expressing opposition to the proposal. These commenters expressed concern about issues including perceived costs, retention time on the animals of RFID eartags, as well as our legal authority under the Administrative Procedure Act (5 U.S.C. 500 *et seq.*) to change the eartag requirements using a

[2] To view the notice, go to: *https://www.regulations.gov/document/APHIS-2017-0016-0001.*

[3] See ADT Trace Performance Metric Report 2013–2022. *https://www.aphis.usda.gov/traceability/downloads/adt-trace-perf-report-2013-2022.pdf.*

[4] To view the notice, supporting documents, and comments we received, go to: *https://www.regulations.gov/document/APHIS-2020-0022-0001.*

notice-based procedure rather than rulemaking.

After reviewing the comments on the July 2020 notice, we determined that withdrawing our recognition of visual-only (non-EID) eartags as official eartags for cattle and bison moving interstate would constitute a change in the application of our regulatory requirements of sufficient magnitude to merit rulemaking rather than the notice-based process we originally envisioned. We also determined that the goal of maximizing transparency and public participation would also best be served through rulemaking in this instance. Therefore, on March 23, 2021, we issued a stakeholder announcement indicating that we would not finalize the 2020 notice, and that we ''would use the rulemaking process for further action related to the proposal.'' [5]

To that end, on January 19, 2023, we published in the **Federal Register** (88 FR 3320–3330, Docket No. APHIS–2021–0020) a proposal [6] to amend the animal disease traceability regulations to require that eartags applied on or after a date 6 months (180 days) after publication in the **Federal Register** of a final rule be both visually and electronically readable in order to be recognized for use as official eartags for interstate movement of cattle and bison covered under the regulations. The proposed rule differed from the 2020 notice in that we referred to electronic identification (EID) tags rather than to RFID tags to recognize the permissibility of other electronically readable technology, in addition to RFID technology, should it become available in the future. We also proposed several other changes to part 86 aimed at clarifying the regulations, including revising the definition of dairy cattle, amending certain provisions pertaining to recordkeeping, and revising certain requirements pertaining to slaughter cattle. We began soliciting comments concerning the proposal for 60 days, ending March 20, 2023, and in response to several requests by commenters, we extended [7] the comment period by 30 days to April 19, 2023.

We received 2,006 comments by the extended date. The comments were from industry groups, producers, veterinarians, State departments of agriculture, and individuals.

Similar to the response to the notice published on July 6, 2020,[8] many of the commenters representing industry organizations and State departments of agriculture regulatory officials were supportive of the proposed rule and agreed that EID furthered the goals of the ADT program with regard to animal traceability. We also received many comments expressing opposition to our proposal. Our responses to those comments are provided below, organized by topic.

General Comments

Several commenters stated that our proposed rule would not improve animal disease traceability because an insufficient number of animals are covered under the proposed rule. These commenters noted that USDA has stated that a participation rate of 70 percent of the nation's cattle herd would be necessary for an ADT program to be effective.

Having a higher percentage of the nation's cattle population officially identified would certainly be a benefit to a robust ADT program, but our focus in this rulemaking is to continue to enhance our ability to respond quickly to high-impact diseases of livestock within the constraints of the animal classes and movements that are currently required to have official identification and the animal classes and movements that are currently exempted.

The source [9] cited by the commenters was the 2009 Congressional testimony of Dr. John Clifford, a former APHIS Deputy Administrator for Veterinary Services. Dr. Clifford was testifying about what measures were in place to survey for and respond to the possible introduction of high-risk foreign animal diseases (FADs) into the United States. His comments should be viewed through that lens and understood to mean that, in order to be fully prepared for a possible incursion of an FAD, an estimated 70 percent [10] of animals of a specific species/sector would need to be traceable. At the time of his testimony, Dr. Clifford estimated that 25 percent of the nation's beef cattle herd participated in the USDA's National Animal Identification System (a voluntary system that prefigured the current ADT program). The higher the number of animals that are traceable, the higher the likelihood that we are able to trace any particular instance of disease and effectively respond.

These statements do not preclude APHIS from taking measures, such as our proposed rule, to move closer to that stated objective, nor do they contradict our claim that our proposal would improve the efficacy of our current ADT program. For the reasons outlined in the proposed rule and summarized above in this document, requiring EID for eartags will improve our ability to trace the cattle and bison that are currently required to have official identification and that meet this requirement with eartags.

A commenter stated that our proposed rule would not improve ADT because our proposal included no measure to solve problems with paper records by, for example, requiring the digitization of paper records used in disease traceback investigations.

We are making no change in response to the commenter. While the regulations do not require the digitization of paper records, APHIS has elsewhere encouraged the use of electronic recordkeeping through efforts such as targeted funding to State and Tribal animal health officials operating under an ADT cooperative agreement to support their electronic recordkeeping systems and maintain their internal databases used for animal disease traceability. Cooperators have used this funding in a variety of ways, including providing accredited veterinarians and livestock markets with free EID readers. Partly as a result of these efforts, electronic interstate certificate of veterinary inspections (ICVIs) are readily available now and frequently used. Moreover, our proposal included editing language in the definition of *interstate certificate of veterinary inspection (ICVI)* in § 86.1 to clarify that electronic ICVIs may be used as an alternative to paper ICVIs. Our intention with respect to this change was to continue to encourage electronic recordkeeping in order to further alleviate the potential problems caused by paper records. However, because electronic ICVIs may sometimes be impracticable for the regulated community, we are not requiring the use of electronic ICVIs.

A commenter stated that typos were not a legitimate basis for major Federal action and claimed that APHIS was suggesting that ranchers ''are doing sloppy work.''

[5] The notice was posted to *https://www.aphis.usda.gov/aphis/newsroom/news/sa_by_date/sa-2021/rfid-traceability-rulemaking.* It is available by contacting *traceability@usda.gov.*

[6] To view the proposal, supporting documents, and the comments we received, go to *https://www.regulations.gov/document/APHIS-2021-0020-0001.*

[7] The comment extension notice was published on March 20, 2023 (88 FR 16576, Docket No. APHIS–2021–0020).

[8] See footnote 4.

[9] *https://www.usda.gov/sites/default/files/documents/5_5_09_Clifford_Dep_Admin_for_Vet_Services_APHIS_National_Animal_ID.pdf.*

[10] More recently, a 2018 World Perspectives study commissioned by the National Cattlemen's Beef Association estimated that a window of 45 percent to 90 percent, with a midpoint of 68 percent, is needed for traceability to have ''national significance.'' (''Comprehensive Feasibility Study: U.S. Beef Cattle Identification and Traceability Systems.'' World Perspectives, Inc. 2018.)

Transcription errors in animal location and movement documents have the potential to significantly impede trace investigations. APHIS recognizes that producers and others who complete these documents typically take care in producing the documents; however, reading and transcribing tag identifiers by hand, especially National Uniform Eartagging System (NUES) tags that may be obstructed with debris or worn down, is a process that is inherently subject to human error. Errors can occur at the level of writing, reviewing, or completing movement documents, and an error in recording a single digit can have major impacts on a trace.

Some commenters stated that APHIS has failed to articulate the need for the proposed EID requirement, as the current ADT program has proven adequate. One of these commenters cited examples of successful disease outbreak control of bovine tuberculosis (TB) in Michigan; mad cow disease in Washington in 2003; and foot-and-mouth disease (FMD) in California in 1929.

Successes in the past do not mean EID is unnecessary. As explained in the proposed rule and summarized earlier in this document, APHIS partners with State veterinary officials each year to test the performance of States' animal disease traceability systems. Results of these test exercises currently show that when State veterinary officials are provided an identification number from an animal that has been identified with an official identification tag, either metal or EID, that has been entered accurately into a data system, over half of States can trace animals to any one of four locations in less than 1 hour (these four locations are: the State where an animal was tagged, the location in-State where an animal was tagged, the State from which an animal was shipped out of, and the location in-State that an animal was shipped out-of-State from). However, lengthy times in the trace test exercises resulted when numbers from visual (metal) tags were transcribed inaccurately, movement records were not readily available, or information was only retrievable from labor-intensive paper filing systems. EID tags and electronic record systems thus provide significant advantage over other forms of official identification to rapidly and accurately read and record tag numbers and retrieve traceability information.

As for the examples cited by the commenter, Michigan was unable to regain TB-free status in the vast majority of the State until improvements to its traceability program were made following the State's implementation of the mandatory use of RFID ear tags in cattle and bison in 2007. Michigan faces a unique challenge in eradicating bovine TB, as the disease is endemic in free-ranging white-tailed deer present in specific areas of Michigan, and the disease can be transmitted between deer and cattle. Because of this, Michigan maintains a split-state status for TB: the State is divided into a Modified Accredited Zone and Accredited Free areas.[11] International trading partners and States have required Michigan to maintain a robust traceability program to continue to allow animals to move internationally or to other States from the Accredited Free areas of Michigan. Utilizing mandatory RFID tags in this traceability program allows immediate uploading of accurate records to the Michigan Department of Agriculture and Rural Development's system, which in turn allows Michigan to show their trading partners proof of where animals have been within the State, and helps to guarantee rapid response in the event of an animal disease emergency.

In addition to allowing for more rapid tracing of animals into and out of TB-positive herds, the mandatory RFID tagging requirement allows Michigan to provide real-time animal movement data for animals leaving the Modified Accredited Zone. This program allows State and Federal animal health officials to trace potentially exposed herds within hours, as opposed to days or weeks, saving both time and money. TB traces in Michigan are linked to source and exposed herds more accurately, which reduces the number of additional herds impacted by quarantine and testing. We believe Michigan's experience further supports our contention that increased use of EID eartags nationwide will improve APHIS's animal disease traceability program.

Regarding the 1929 outbreak of FMD in California, historically, cattle movement in the United States was much smaller. Animals today can be transported quickly and easily across State lines, allowing for a much more rapid and uncontrolled spread of disease. While the United States was fortunate to contain the disease in 1929, containing an outbreak would be far more difficult today. Moreover, the cost of containment, eradication, and the loss of export markets would far outweigh the cost of EID tags.

Regarding the 2003 case of bovine spongiform encephalopathy (BSE, ''mad cow disease'') in Washington, the diseased cow was traceable to Canada. The United States was unable to trace all the cows in the diseased cow's cohort, leading to suspicion that more cows with BSE existed in the United States, which resulted in negative impacts to cattle prices and export markets that lasted several years.[12] We consider this further support for improving the animal disease traceability program, as we believe that a more effective and efficient animal disease traceability program may have prevented those impacts.

As we have previously stated, in order to be fully prepared for a possible incursion of a high-risk FAD, an estimated 70 percent of each species/sector would need to be traceable. To be an effective tool for disease control, the traceability must be successful to the source of the disease and exposed animals within the time window of the particular disease's exposure and transmission parameters. This rulemaking furthers this goal.

Some commenters claimed that the ADT program's goal to trace an animal from birth to death in less than 24 hours was flawed, as birth-to-death traceability is not needed for fast-moving diseases such as FMD. The commenter suggested that the program need only trace where the infected animal has been in the last few days. The commenters also claimed that slow-moving diseases such as TB do not require rapid traceback.

The ADT program does not have a goal of tracing an animal from birth to death in less than 24 hours; the ADT program's goal is to be able to trace animals' movements completely and as rapidly as necessary to contain the disease in question, which depends on the speed of disease transmission.

Traceability is necessary for controlling both fast-moving diseases, like FMD, as well as slower-moving diseases, like TB and brucellosis. In both cases, speed of data retrieval and information sharing is important for efficiently and effectively completing a trace investigation. Responders can better identify animals that may have come in contact with an affected animal, which sometimes can number in the thousands or tens of thousands, implement mitigation strategies, and thereby minimize the economic impact of outbreaks to the industry. This speed of information retrieval and sharing is

[11] The Modified Accredited Zone is currently comprised of 4 counties; the State's remaining 79 counties are Accredited Free areas (*https://www.michigan.gov/mdard/animals/diseases/bovine-tuberculosis*).

[12] Coffey, B., Mintert, J., Fox, J.A., Schroeder, T.C. and Valentin, L., 2005. The economic impact of BSE on the US beef industry: product value losses, regulatory costs, and consumer reactions. Kansas State University Agricultural Experiment Station and Cooperative Extension Service, MF–2678.

enhanced when electronic identification and recordkeeping methods are utilized.

A commenter stated that use of EID eartags would not be enough to help control a potential FMD outbreak, and that prevention should be the first line of defense.

APHIS agrees that a response to FMD in the United States would require a multifactorial approach. As explained in Dr. Clifford's 2009 testimony [13] before Congress, APHIS' response plan includes specific emergency response guidelines; coordination with Departments and Agencies that will support and partner with USDA in emergency response; rapid response teams stationed around the country; access to personnel through the International Animal Health Emergency Response Corps; the National Veterinary Stockpile; and guidelines regarding the use of FMD vaccine.

Moreover, while prevention and biosecurity are necessary first-line defenses, we do not agree that they are sufficient risk mitigation strategies alone. EID eartags will make the process of tracing infected and exposed animals more efficient and will improve our implementation of mitigations, like tracing animals forward or utilizing vaccination or regionalization strategies. EID would be critical to reopening export markets closed as a result of an FMD outbreak, as the rapid tracing afforded by EID would help the United States demonstrate freedom from disease and disposition of all infected and exposed animals.

A commenter stated that early diagnosis and good animal husbandry are more important to disease control than ADT, as evidenced by the failure of EID to prevent the porcine epidemic diarrhea (PED) outbreak of 2013.

While we agree that good animal husbandry is important for preventing disease and that early diagnosis can help prevent its spread, this does not negate the importance of an ADT program, which can help us contain potentially devastating disease outbreaks before they can do substantial damage.

The commenter is correct that electronic identification of swine moving interstate would not have materially impacted the spread of PED. However, this is due to the nature of the disease and swine industry practices, rather than a failure of EID identification. The primary mechanism of PED spread was through fomites (*e.g.,* pig feed, trucks, etc.) and not animal-to-animal contact where tracing would have been of greater benefit. In contrast, diseases of cattle and bison, such as TB, brucellosis, and FMD, often are transmitted by animal-to-animal contact and, when the cattle or bison are moving in interstate commerce, the diseases can rapidly damage the cattle and bison industry in multiple States.

Some commenters disagreed that our proposal would address animal disease outbreaks because they claimed the risk of outbreaks of diseases of livestock originates from people crossing the border into the United States. Commenters specifically cited the risk of human-to-animal transmission of TB.

The commenter's claim that disease outbreaks of TB in cattle and bison are largely the result of zoonosis, and exposure to infected humans is not supported by data. Information from APHIS' National Tuberculosis Eradication Program indicates that TB is usually spread through the purchase of infected animals or exposure to infected cattle or wildlife. While human-to-animal transmission of TB may periodically occur, genomic testing shows the incidence to be low.

Some commenters disagreed that our proposal would address livestock disease outbreaks because they claimed the risk of livestock disease outbreaks originates from imported cattle and beef. The commenters suggested that APHIS focus its efforts on restricting imports to prevent the introduction of livestock disease rather than improving ADT.

This rulemaking is limited in scope to improving our national animal disease traceability program; restrictions on the importation of live animals and animal products are outside of its scope. We note that, under our regulations in 9 CFR part 93, APHIS only allows the importation of live animals from countries that meet certain freedom from disease testing requirements. Under 9 CFR part 94, APHIS similarly restricts the importation of animal products based on the animal disease status of the exporting region. Animals and animal products that do not meet these requirements may not be imported into the United States.

A commenter stated that the proposed rule does not mention biosecurity and, therefore, is not focused on disease prevention.

We agree with the commenter that biosecurity is important to preventing disease and encourage producers to follow biosecurity practices. The commenter is correct that this final rule is not focused on disease prevention. As acknowledged in the proposed rule, the intent of the proposed rule was not to prevent disease epidemics. Rather, it would facilitate containing disease outbreaks before they can do substantial damage to the U.S. cattle and bison industries. This final rule is specifically focused on improving our ability to trace animals accurately and rapidly in order to prevent that potential damage.

Many commenters who opposed the proposed EID tag requirement based their opposition on issues related to food safety. Commenters stated that the majority of food-borne illnesses in meat are the result of practices at the slaughterhouse and in processing and handling. Since animal identification programs end at the time of slaughter, commenters argued that requiring EID tags on cattle will not increase food safety.

Within the USDA, food safety of meat and meat food products falls under the purview of the Food Safety and Inspection Service (FSIS). APHIS does not have statutory authority to regulate for food safety. The EID eartag requirement is intended to facilitate animal disease traceability, thereby improving our ability to trace outbreaks of diseases of livestock in live animals and more efficiently control or eradicate these diseases. This is consistent with our statutory authority under the AHPA.

It was further stated that, to address food safety and animal disease, APHIS should increase oversight and testing at the large meat processing plants. The commenters felt that would be more effective in preventing the spread of disease than requiring EID eartags.

As noted above, FSIS is a separate agency of USDA that regulates the slaughter and processing of meat and meat food products. APHIS does not provide oversight of the slaughter or processing operations; however, APHIS conducts surveillance for domestic animal diseases, such as brucellosis and TB, and some foreign animal diseases in certain species through slaughter surveillance. APHIS regularly evaluates its slaughter surveillance programs for efficacy; however, we disagree with the commenter that more stringent oversight of such facilities would prove more effective than requiring EID tags. Slaughter facilities are a terminal point, and cattle and bison may pass through multiple intermediate locations and commingle with animals from other premises and of other health statuses prior to slaughter. In the event of a disease outbreak, addressing this possible intermediate movement requires rapid and accurate traceability of all potentially affected livestock.

Some commenters asked us to reinstate mandatory country of origin labeling (COOL) in order to have a successful traceability program. Some commenters asked whether we intended

[13] See footnote 9.

to use EID tags for the purposes of COOL.

COOL pertains to the labeling of food products and is not related to APHIS' animal disease traceability program. Moreover, COOL was never under APHIS' purview, but under the purview of the Agricultural Marketing Service (AMS).

Some commenters expressed their support for the continued exemption of cattle under 18 months of age from official identification requirements.

The regulations will continue to exempt most feeder cattle (beef cattle less than 18 months of age) from official identification requirements.

A commenter stated that ADT should only apply to breeding cattle or cattle in interstate commerce. Conversely, other commenters recommended that we apply the EID tag requirement to all cattle and/or that all cattle should be tagged at birth or before being sold, as this would improve our ability to locate diseased animals and lessen the effects of a disease outbreak. Some of these commenters added that this issue should be addressed in a separate rulemaking.

We will consider the commenters' recommendations in the future; however, changing the type of cattle needing official identification is outside the scope of this rulemaking. Should APHIS decide to change the type of cattle that require official identification in the future, this process would occur through rulemaking that would solicit public comment.

Some commenters expressed concern about APHIS expanding ADT requirements to encompass other types of cattle in the future.

This rulemaking is only intended to address the transition to EID official eartags for cattle and bison that are currently required to have official identification.

Some commenters expressed confusion regarding whether the EID tag requirement applied to their animals. Commenters provided various examples of beef cattle that do not move interstate, or that moved interstate but were less than 18 months of age. It was stated that the rule would require producers to tag their direct-to-slaughter cows and bulls. Similarly, two commenters requested that we exclude small producers from the EID eartag requirements in order to reduce burden on these entities.

This final rule does not change the types of animals to which official identification requirements apply, nor does it change the categories of animals that are exempted from official identification requirements. Under the current regulations in § 86.4(b), which this final rule does not change, the following categories of cattle and bison are subject to official identification requirements for interstate movement: all sexually intact cattle and bison 18 months of age or over; all female dairy cattle of any age and all male dairy cattle born after March 11, 2013; cattle and bison of any age used for rodeo or recreational events; and cattle and bison of any age used for shows or exhibitions. Cattle and bison are exempted from official identification requirements if they are going directly to slaughter.

Because of these strictures, many small entities have cattle that are excluded from the requirement currently, including many of the commenters who asked whether the rule applies to them. Beef feeder cattle under 18 months of age are not subject to the identification requirements. Direct-to-slaughter cattle, including cull cattle, are not subject to the identification requirements. Cattle and bison that do not move interstate are not subject to the identification requirements, unless required by APHIS program disease regulations in 9 CFR subchapter C.

Some commenters stated that when the new EID tag requirement goes into effect, we should continue to exempt animals moved between States on pasture-to-pasture movement permits, *i.e.,* commuter herd agreements, from the requirements for official identification.

The EID tag requirement does not change the categories of animals that are subject to, or exempted from, the requirements for official identification.

Under a commuter herd agreement between a livestock owner and State or Tribal animal health officials, cattle and bison may be moved interstate between two premises, without a change of ownership in the course of normal livestock operations, subject to the conditions of the agreement. The regulations in § 86.4 provide for interstate movement of commuter herds under commuter herd agreements. See 9 CFR 86.4(b)(1)(i)(A). The EID tag requirement does not affect those regulations and, therefore, does not have any implications for the interstate movement of commuter herds.

A commenter stated that animals involved in private treaty sales for the purpose of breeding should be exempt from EID tag requirements when moved interstate.

This comment is outside the scope of this rulemaking. Per § 86.2(b), no person may move covered livestock interstate or receive livestock moved interstate unless all requirements of part 86 are met. Private treaty sales of breeding cattle are required to meet these requirements, including official identification and an ICVI.

A commenter stated that allowing animals to move through a livestock facility to a slaughter establishment where a backtag can be applied, in accordance with § 86.4(b)(1)(ii)(B), leaves a potential gap in traceability to the premises of origin.

Section 86.4(b)(1)(ii) refers to a situation in which cattle are exempted from the requirement for official identification. Exemptions from the requirement for official identification are outside the scope of this rulemaking.

A commenter stated that finalizing this proposed rule would ''invite limitless incremental regulation from other agencies.''

The commenter's stated supposition for this statement is that this rulemaking represents a concerted effort by the Federal Government, as a whole, to wrest livestock management decisions from individual producers. APHIS has no intent to do so, nor is it aware of any such effort.

The same commenter opined that the rule could be used by APHIS as a basis for incremental further expansion of the ADT program, citing, as purportedly analogous examples, requirements by the Security and Exchange Commission regarding environmental, social, and governance reporting, and policies by the Food and Drug Administration regarding the use of antibiotics in livestock.

APHIS has no authority over the regulatory actions and policies of other agencies. However, as noted above, the proposed rule is a distinct action meant, primarily, to change the official eartag requirements for cattle and bison covered by the ADT regulations in order to improve its emergency response and ongoing disease control and eradication programs. The proposed rule is not intended as part of a suite of interlocking, incremental regulatory changes to the regulations, and any possible future revisions to the regulations would be through proposed rules with the opportunity for public comment.

Some commenters, while generally supporting the use of EID eartags for official identification of cattle and bison, believed that such use should be voluntary rather than a requirement.

The use of EID official eartags has been voluntary for many years. In our view, and as stated above, continuing to allow the use of EID eartags by producers on a voluntary basis will not provide the degree of enhancement to our traceability capacity that is needed

for optimal animal disease investigation and control.

We also received a number of comments regarding the public comment period and outreach efforts related to this rulemaking. A few commenters stated that more stakeholder outreach was needed. Some commenters stated that APHIS ignored previous stakeholder outreach in drafting our proposed rule. Some commenters requested an extension of the comment period, ranging from 30 days to 90 days, to allow more time for public input.

We extended the comment period for the proposed rule by 30 days, which we consider appropriate given our prior outreach efforts to stakeholders. We disagree that our outreach efforts were inadequate or that the feedback received during our outreach efforts was ignored. As stated in the proposed rule and summarized earlier in this document, outreach included meetings with State officials and APHIS Veterinary Services field officers; nine public meetings that solicited attendance from cattle and bison industry members, as well as impacted States and Tribes; the July 2020 notice seeking public comment for 90 days; as well as the January 2023 proposed rule, which solicited comment for a total of 90 days. All input and comments received from these efforts were considered when drafting this rulemaking.

Effective Date and Implementation

Some commenters advocated grandfathering in existing eartags, *i.e.,* recognizing visual tags, such as National Uniform Eartagging System eartags, as official eartags for animals tagged with them prior to November 5, 2024, the effective date of the EID tag requirement.

We agree with these commenters. As we noted in the proposed rule, visual eartags applied to animals prior to November 5, 2024 will be recognized as official eartags for the life of the animal.

Some commenters expressed concern about the effective date of November 5, 2024, stating that 6 months was a relatively short amount of time to notify producers of the new requirements and for producers to meet the EID tag requirement. Other commenters expressed support for our proposed timeline.

We believe that an effective date of November 5, 2024 provides sufficient time for stakeholders to comply with the new requirements. APHIS has engaged in extensive outreach efforts regarding the use of EID eartags, as summarized earlier in this document, and it has ensured that the new requirements will only apply to eartags applied to animals after the effective date.

Two commenters stated that implementation of the proposed rule would be difficult due to a general labor shortage.

We note that producers may apply official eartags to their animals themselves. Whether producers have tags applied to their animals at approved tagging sites, apply tags to their animals themselves, or hire labor to apply tags to their animals, we do not believe there is more labor involved in the application of EID eartags as opposed to applying eartags that are only visually readable.

Multiple commenters expressed concern about potential shortages of EID tags in light of supply chain and manufacturing challenges. Some commenters mentioned that EID tags are often backordered or that there are high wait times for EID tag orders. Some commenters recommended we create a contingency plan in the event EID tags required by this rulemaking are not available once the final rule goes into effect.

APHIS ADT staff have had frequent conversations with manufacturers of official devices and have been assured that manufacturing and shipping capacity is adequate for the projected number of cattle requiring official identification for interstate movement.

APHIS is aware of supply chain and manufacturing disruptions due to the COVID–19 pandemic, but these issues have been resolved. APHIS is also aware of long wait times due to customization or brand preferences that are desired by the producer, but the regulations do not require such customizations or that any specific brand be used. We do not believe either of these issues indicate that a current shortage exists or that a future shortage is likely, and the commenters have not provided any additional evidence of reasonably foreseeable supply chain issues.

Finally, as discussed in further detail later in this document, we believe that the streamlining changes we proposed to the approval process for new EID devices will help insulate against unforeseen supply chain disruptions.

Definitions (§ 86.1)

In § 86.1, we proposed to revise the definitions of *approved tagging site, dairy cattle, interstate certificate of veterinary inspection (ICVI),* and *official eartag.* We also proposed to add a new definition for *Official Animal Identification Device Standards (OAIDS).* Comments we received for each of the revisions and addition to § 86.1 are addressed below.

Approved Tagging Site

The current regulations define an *approved tagging site* as ''A premises, authorized by APHIS, State, or Tribal animal health officials, where livestock may be officially identified on behalf of their owner or the person in possession, care, or control of the animals when they are brought to the premises.'' In order to offer greater clarity regarding the nature of an approved tagging site by specifying that such sites are where official identification tags are physically applied to animals, we proposed to revise this definition to read as follows: ''A premises, authorized by APHIS, State, or Tribal animal health officials, where livestock without official identification may be transferred to have official identification applied on behalf of their owner or the person in possession, care, or control of the animals when they are brought to the premises.''

One commenter, while expressing support, suggested we also revise the definition to require the physical address of the originating premises to be recorded alongside the animal's official identification number in order to address a purported ambiguity in the current regulations. The commenter stated that, occasionally, livestock exempt from the official identification requirements for interstate movement by § 86.4(b)(1)(i)(C) that arrive to an approved tagging site only have their official identification numbers recorded with the physical address of their originating premises if they receive their official identification at the tagging site, while, for livestock that arrive already bearing official identification and only have backtags applied at the tagging site, no record is made of their originating premises.

We are making no change in response to this comment. Cattle moving interstate, whether or not already bearing official identification, must be accompanied by an ICVI or alternative movement document. (See § 86.5(a).) These records contain the physical address of the animal's originating premises. Therefore, in both scenarios referenced by the commenter, records correlating the animal's official identification number to their originating premises already exist, and we do not agree that the definition of *approved tagging site* is an appropriate place to reference these records requirements.

However, if States or Tribes wish to require an approved tagging site to complete this additional recordkeeping, they could do so as part of their State or Tribal agreements for authorizing an

approved tagging site, as requirements for approved tagging sites may vary according to the relevant authority.

One commenter asked whether a ranch was considered an approved tagging site and, if so, whether this involved an approval process. Another commenter asked how a location can become an approved tagging site.

Per the definition of *approved tagging site,* approved tagging sites may be authorized by State, Federal, or Tribal animal health officials. Individual States maintain lists of the approved tagging sites in their State. The commenters are encouraged to contact the appropriate animal health official in their area [14] to receive a list of approved tagging sites in their State, as well as information regarding becoming an approved tagging site. Requirements for approved tagging sites may vary depending on the relevant authority.

A commenter stated that the process for becoming an approved tagging site should be consistent with the process for becoming a Secondary Tagging Site for the Agriculture Marketing Service Process Verified Program.

We are making no change in response to the comment, as approved tagging sites, as defined in § 86.1 are not related to Process Verified Programs. As mentioned above, approved tagging sites may be authorized by State, Federal, or Tribal animal health officials. Accordingly, the requirements for authorizing an approved tagging site may vary depending on the relevant authority.

One commenter asked whether all in-State general auction markets were approved tagging sites.

No. In-State general auction markets may become approved tagging sites if authorized as such by APHIS, State, or Tribal animal health officials.

Dairy Cattle

The current definition for *dairy cattle* reads, ''All cattle, regardless of age or sex or current use, that are of a breed(s) used to produce milk or other dairy products for human consumption, including, but not limited to, Ayrshire, Brown Swiss, Holstein, Jersey, Guernsey, Milking Shorthorn, and Red and Whites.'' We proposed to add to this definition cattle that are reared under the same management practices as purebred dairy cattle. The definition in the proposed rule read: ''All cattle, regardless of age or sex, breed, or current use, that are born on a dairy farm or are of a breed(s) used to produce milk or other dairy products for human consumption, or cross bred calves of any breed that are born to dairy cattle including, but not limited to, Ayrshire, Brown Swiss, Holstein, Jersey, Guernsey, Milking Shorthorn, and Red and Whites.'' Commenters raised concerns that caused us to further revise this definition, which we discuss later in this document.

We also proposed changes throughout part 86 to align the regulations with this revised definition. This included revising § 86.4(b)(1)(iii)(B) to include the offspring of dairy cattle in the list of cattle subject to the official identification requirements, as well as revising § 86.5(c)(7)(ii) to require that the official identification numbers of all dairy cattle, regardless of whether the dairy cattle are sexually intact, must be recorded on ICVIs.

Multiple commenters expressed their support for the revised definition for *dairy cattle* presented in the proposed rule, stating that the revision would help eliminate confusion and ambiguity.

We agree with the commenters. Eliminating ambiguity in the definition will help ensure that all dairy cattle, which have an increased risk of disease, meet the appropriate requirements for official identification and movement documentation.

A commenter requested we clarify whether our proposed revision intends to capture beef animals ''born on a dairy farm,'' and, if so, requested that we clarify that these animals would be required to have official identification if moved interstate. The commenter also noted that compliance challenges may present themselves in situations where an animal's farm of birth is unknown.

The increased disease risk relevant to animals born on a dairy farm that we discussed in the proposed rule applies specifically to beef/dairy cross bred cattle born on a dairy farm. We agree with the commenter that the phrase ''born on a dairy farm'' is unclear, as it may give the false impression that it applies to beef animals born on a dairy farm that are not beef/dairy cross bred animals. Therefore, we are revising our proposal to address this potential confusion. The revised definition of *dairy cattle* will read as follows: ''All cattle, regardless of age or sex or current use, that are of a breed(s) or offspring of a breed used to produce milk or other dairy products for human consumption, including, but not limited to, Ayrshire, Brown Swiss, Holstein, Jersey, Guernsey, Milking Shorthorn, and Red and Whites.''

Some commenters, while expressing their support for a revised definition, asked us to replace the phrase ''cross bred calves of any breed'' in the revised definition presented in the proposed rule with the phrase ''cross bred cattle of any breed'' to further eliminate confusion regarding to which animals the definition applies.

The commenters are correct that we intended to capture cross bred cattle of any age, rather than only calves, in our proposed revised definition. We believe the modification to the proposed definition provided above addresses these commenters' concern.

One commenter asked whether the change to the *dairy cattle* definition would apply across all Federal regulations administered by APHIS. The commenter stated that consistency in definitions would prevent discrepancy and aid enforcement.

In the proposed rule, we proposed to revise definitions in 9 CFR parts 71, 77, and 78 to correspond with the changes to the definitions that we proposed for part 86. While we accounted for the definitions of *official eartag* and *interstate certificate of veterinary inspection (ICVI),* we erroneously neglected to account for the definition of *dairy cattle,* which the commenter correctly points out is also used in part 78. Therefore, we will revise the definition of *dairy cattle* in part 78 to correspond with the change to the definition made in part 86.

Some commenters disagreed with our proposed revised definition, arguing that there is no increased risk of disease transmission from cattle that are reared under the same management practices as purebred dairy cattle.

We disagree with the commenters. As stated in the proposed rule, dairy farm management practices, such as pooling colostrum from multiple cows for many calves, commingling calves at different locations during their lifetimes, and movement to many destinations, result in a higher risk of disease transmission. Beef/dairy crosses born on dairy farms are likely to be exposed to these practices, especially in early life; therefore, they are at an increased risk of disease transmission.

Two commenters stated that our revised definition would discourage producers from including beef/dairy cross bred calves as part of their operations.

The commenter provided no evidence to support this claim. We also note that APHIS' operational guidance has consistently held that beef/dairy cross bred cattle fall under the definition of dairy cattle, and are therefore already required to have official identification; our change to the dairy cattle definition codifies this longstanding guidance

[14] Contact information for State animal health officials (SAHOs) may be found at: *https://www.usaha.org/saho.*

regarding how to interpret the regulations.

Interstate Certificate of Veterinary Inspection (ICVI)

We proposed to add editorial and formatting changes to the definition of *interstate certificate of veterinary inspection (ICVI)* to clarify that electronic ICVIs may be used.

A commenter stated that APHIS should require the recording of official identification on ICVIs at the most specific applicable level. The commenter opined that official individual animal identification numbers should be recorded on ICVIs even when animals are identified using a group/lot identification number (GIN).

We are making no changes in response to the comment. A GIN is used to uniquely identify a unit of animals of the same species that is managed as one group throughout the preharvest production chain. Animals identified using a GIN are not required to have the GIN, or any additional animal identification number, affixed to them. Instead, the GIN is recorded on documents accompanying the animals as they move interstate. Because these animals move as a unit, a GIN provides sufficient information to identify the animals in the event of a trace. We also note that cattle and bison typically do not move on GINs due to the current industry structure within the United States.

A commenter asked us to clarify in the definition of *ICVI* that accredited veterinarians who issue ICVIs must be licensed and accredited in the State of origin of the animal requiring documentation, as the current definition only requires that issuing veterinarians are licensed in State of origin and federally accredited.

We are making no changes in response to the commenter, as we do not agree that the definition of *ICVI* is an appropriate place to state the regulations and standards relevant to accredited veterinarians. The commenter is incorrect that the definition of *ICVI* lists licensure or accreditation requirements for veterinarians. Requirements for licensure and accreditation for veterinarians are covered in 9 CFR part 161.

Official Animal Identification Device Standards (OAIDS)

We proposed to add a definition of *Official Animal Identification Device Standards (OAIDS)* to replace the Animal Disease Traceability General Standards document. The proposed OAIDS, like the existing Standards document, provides guidelines, technical standards, and specifications for tag manufacturers requesting APHIS approval of new official identification devices. As stated in the proposed rule, in addition to edits corresponding to changes proposed to the regulations, changes to the document include the following:

- Accepting EID device testing equivalent to International Committee for Animal Recording (ICAR) testing and allowing APHIS to consider requests, on a case-by-case basis, for approval of alternative field trials or eartags with previously generated verifiable data if equivalency to the standards is demonstrated;
- Modifying the field trial requirements by reducing timelines for the three approval statuses (trial: from 0–12 months to 0–6 months; preliminary: from 12–24 months to 6–12 months; and conditional: from 24–36 months to 12–36 months), reducing the number of required field trial locations (from at least 6 to at least 2), and reducing the number of cattle and bison required for field trials (from a minimum of 1500 to a minimum of 300); and
- Reducing the timeframe before allowing unlimited sales of devices from a minimum of 24 months to a minimum of 12 months if devices meet the required performance standards.

Numerous commenters expressed support for this addition and the changes we proposed to make to the document. These commenters noted that streamlining the approval process for EID devices will ensure availability of tags, insulate against supply chain disruptions, and help facilitate the introduction of new technologies.

We agree with the commenters. As stated in the proposed rule, our changes are meant to encourage manufacturers to seek APHIS approval of new official identification devices.

One commenter expressed concern regarding reducing the timeframe before allowing unlimited sales of a device from 24 months to 12 months, stating that this could compromise assurance of the devices' quality and longevity.

We are making no changes in response to the commenter. Tag retention, durability, safety, and efficacy are of utmost importance to APHIS. Our approval process for EID eartags continues to require testing and field trials or performance data that ensure the eartags meet the required standards. We note the benchmark of unlimited sales is conditional and does not constitute full approval. The timeframe for full approval will remain 36 months (30 for swine); prior to full approval, manufacturers are required to have a mechanism in place to collect and report tag failure data to APHIS.

We believe that the tag standards listed in the OAIDS, including the aforementioned 12-month timeframe for unlimited sales, will maintain a high standard of quality without discouraging manufacturers from applying for official status. As we noted in the proposed rule, we determined that requiring manufacturers to wait 24 months before allowing unlimited sales of a device that met the required performance standards could have been inhibiting manufacturers from seeking APHIS approval.

One commenter stated that the proposed changes to the OAIDS render the proposed rule a major rule, as the document allows for ''regulatory flexibility.''

Under the Congressional Review Act (CRA), major/non-major designations occur at the final rule stage and are the purview of the Office of Management and Budget based on an assessment of expected annual costs associated with the rule. APHIS has no discretion to label the rule major or not major under the CRA. However, we note that the commenter's stated basis for considering the rule major does not align with the criteria in the CRA, which is whether the rule is likely to result in (1) an annual effect on the economy of $100,000,000 or more; (2) a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or (3) significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic and export markets. 5 U.S.C. 804(2).

Two commenters stated we should reduce the required lifespan of a device to 3 years from 10 years. One commenter stated 3 years was sufficient because the typical lifespan for beef cattle going to slaughter is 18–24 months. The other commenter stated a 10-year requirement was a hindrance to the adoption of future technologies.

The commenters are incorrect that the requirements specify that tags should have a lifespan of 10 years. The OAIDS states that a tag is expected to remain on an animal in a physically functional state for the animal's expected lifetime, which, for cattle and bison, is up to 15 years.

We disagree with the commenters that tags should only have a lifespan of 3 years. Cattle and bison under 18 months of age and cattle and bison going

directly to slaughter are exempt from the requirements for official identification, rendering their example irrelevant. Moreover, a device that only functions for 3 years would add burdensome costs to producers, as they would need to replace tags more frequently. It would also make record retention and tracing more difficult, especially for longer-lived animals, as the animals would be associated with a different identification number every 3 years.

Official Eartag

The current definition of official eartag reads, ''An identification tag approved by APHIS that bears an official identification number for individual animals. Beginning March 11, 2014, all official eartags manufactured must bear an official eartag shield. Beginning March 11, 2015, all official eartags applied to animals must bear an official eartag shield. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.'' We proposed to revise this definition to remove language referencing the 2014 and 2015 dates, which are no longer relevant. Our proposed revised definition reads as follows: ''An identification tag approved by APHIS that bears an official identification number for individual animals. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.''

One commenter asked that we establish a standard for a ''high retention rate'' to aid State officials in enforcement.

Retention rates required for approved EID tags have already been established in the former Animal Disease Traceability General Standards document and are included in the OAIDS. For cattle and bison, device loss rates must not exceed 1 percent annually or 3 percent in a 3-year period.

Additional Definitions

One commenter asked us to define the term *premises,* as one of the dictionary definitions for ''premises'' necessitates a deed.

We are making no changes in response to the commenter, as we believe the regulations are sufficiently clear that a premises in part 86 relates to a geographical location, not a deed. For example, the definition of a *premises identification number (PIN)* in § 86.1 describes a premises as ''a geographically distinct location.''

Recordkeeping Requirements (§ 86.3)

Section 86.3 addresses recordkeeping requirements for official identification. Current § 86.3(a) states that any State, Tribe, accredited veterinarian, or other person or entity who distributes official identification devices must maintain for 5 years a record of the names and addresses of anyone to whom the devices were distributed. We proposed to add a requirement to that paragraph that official identification device distribution records must be entered by the person distributing the devices into the Tribal, State, or Federal databases designated by APHIS.

We also proposed to add a new paragraph (b), which would state that records of official identification devices applied by a federally accredited veterinarian to a client's animal must be recorded in a readily accessible record system to help ensure such records are available to APHIS for traceback investigations.

Finally, we proposed to add a new paragraph (d), stating that records required under paragraphs (a) through (c) of § 86.3 must be maintained by the responsible person or entity and be of sufficient accuracy, quality, and completeness to demonstrate compliance with all conditions and requirements under part 86. The proposed new paragraph further required that APHIS be allowed access to all records during normal business hours, to include visual inspection and reproduction (*e.g.,* photocopying, digital reproduction), and the responsible person or entity must submit to APHIS all reports and notices containing the information specified within 48 hours of receipt of request for records.

Two commenters asked us to amend § 86.3(a) to allow the person distributing EID eartags to provide records to a State official, via a spreadsheet, and the State official to enter the records into a State or Federal database.

We are making no changes in response to the commenter, as we interpret our proposed change to § 86.3(a) as written to already allow for the arrangement described by the commenter. A person who provides records to a State official to enter into a State or Federal database would fulfill the requirement of entering the official identification device distribution records into an acceptable database.

Two commenters asked us to amend § 86.3(b) (redesignated in our proposal as § 86.3(c)) to read, ''Approved livestock facilities must keep any ICVIs or alternate documentation that is required by this part for covered livestock to enter the facility through interstate movement'' rather than ''Approved livestock facilities must keep any ICVIs or alternate documentation that is required by this part for the interstate movement of covered livestock that enter the facility.'' The commenters stated that this change would clarify that this requirement is pertains to livestock moving to the market from out-of-state, rather than moving from the market to an out-of-state facility.

We are making no change in response to the commenter, as we believe the regulations as written are sufficiently clear that this paragraph refers to livestock that enter an approved livestock facility from out of state.

One commenter stated that the proposed rule was not specific enough about who was responsible for recordkeeping. The commenter asked whether the responsible party was the veterinarian, producer, or tag distributor.

We disagree that these requirements are not sufficiently specific. In our proposed rule, § 86.3(a) specifies that any State, Tribe, accredited veterinarian, or other person or entity who distributes official identification devices is responsible for maintaining records of the names and addresses of anyone to whom the devices were distributed. In other words, the recordkeeping requirements of § 86.3(a) apply to whoever distributes the official identification device in any one transaction, whether that be a State, Tribe, accredited veterinarian, or other person or entity. We also note that a producer applying official identification devices to their own animals, but not distributing the official identification devices to anyone else, does not fall under § 86.3(a).

In our proposed rule, § 86.3(c) specifies that approved livestock facilities are responsible for keeping ICVIs or alternate documentation that is required by part 86 for the interstate movement of covered livestock that enter the facility.

Two commenters stated that we should amend proposed § 86.3(d) to place the responsibility for ensuring ''accuracy, quality, completeness'' of an ICVI on the veterinarian who created the ICVI, not the approved livestock facility that maintains the document.

The commenters have misinterpreted the regulations. Contrary to the commenters' implication, § 86.3(d) does not specifically or exclusively place

responsibility for the accuracy, quality, and completeness of ICVIs on approved livestock facilities. Section 86.3(d) requires ''the responsible person or entity'' to maintain records required under § 86.3(a) through (c) and to ensure that they are accurate, of quality, and complete. Multiple persons or entities may bear this responsibility. Standards for accredited veterinarians in 9 CFR part 161 stipulate that accredited veterinarians cannot issue documents unless they have been ''accurately and fully completed'' (9 CFR 161.4). This standard applies to ICVIs or alternative documentation referred to in § 86.3(c). The approved livestock market maintaining ICVIs or alternative documentation as required by § 86.3(c) is responsible for providing accurate information, such as information regarding which animals have been sold and to whom, to a veterinarian creating ICVIs for animals leaving the facility. Ensuring the continued accuracy, quality, and completeness is also a part of the proper maintenance of records and is not a standard limited to their creation.

Some commenters asked us to shorten the 48-hour timeframe for entities to submit to APHIS all requested records to 24 hours, stating that 48 hours was too long. Other commenters asked us to increase this timeframe to 72 hours, as many livestock markets operate 1 day each week and may not have the staff availability to meet the 48-hour requirement and to align with the potential 72-hour national stop movement order for livestock transport.

We believe that 48 hours is a reasonable compromise. While animal traces should occur as quickly as possible, 24 hours may not be practical for some markets, due to staffing and availability constraints. The 72 hours cited by commenters refers to a potential emergency response for highly contagious disease outbreaks, in which all animal movement would be stopped for 72 hours. This potential order should not affect the ability to provide information necessary for a trace, and it would be disadvantageous to delay tracing until the order were lifted, as the delay may inhibit the speed of our response to a disease threat.

One commenter asked whether training on database use will be provided to those responsible for recordkeeping.

We are unsure to which database the commenter is referring. The proposed rule referred to three different types of recordkeeping: (1) for recordkeeping of device distribution, APHIS provides training for APHIS databases such as the Animal Identification Management System (AIMS); (2) for recordkeeping of applying official ID, accredited veterinarians may use AIMS or various medical record systems and receive training from their vendors; (3) finally, State officials maintain records of ICVIs and tag distributions in the State's regulatory database for which APHIS does not provide training.

One commenter asked what would happen to records if an individual, such as an accredited veterinarian, responsible for recordkeeping went out of business.

Tag distributors must maintain records in accordance with § 86.3, whether or not their business is still in service.

One commenter asked us to include the specific requirements of recordkeeping in the final rule, rather than in the OAIDS, to increase compliance.

We are making no changes in response to the commenter. Apart from streamlining the approval process of new EID tags and applying changes corresponding to this rulemaking, the OAIDS contains the same information as the previous iteration of the document, titled the Animal Disease Traceability General Standards document. As we have not historically experienced problems due to the location of the information contained within the Standards document, we do not have reason to believe that the OAIDS is an unsuitable location for the information contained therein.

One commenter asked us to add a time requirement of 48 hours for entering records of distributed devices into an acceptable database.

As we have not experienced problems with the timely entrance of distribution records into a database, we disagree that specifying a time requirement in the regulations is necessary. The entry into a database should occur immediately upon distributing the tags, because the tags may be applied upon receipt to an animal for immediate movement.

One commenter asked whether a producer who applied tags to their animals themselves would be responsible for the recordkeeping requirement in § 86.3.

No. Under § 86.3(a), a person distributing tags must maintain for 5 years a record of the names and addresses of anyone to whom the devices were distributed. If a producer is applying tags to their own animals and not distributing tags to another person, this requirement does not apply to them.

One commenter stated that they would prefer if States had consistent forms for submitting recordkeeping information regarding EID tag distribution to States.

This is outside the scope of this rulemaking. APHIS does not mandate the type of form States must use for this recordkeeping.

Finally, in reviewing the proposed rule while drafting this final rule, we noticed that our proposed § 86.3(a) incorrectly omitted mention of distribution records kept by large producer organizations that redistribute tags to their members in their own databases. In order to prevent the interpretation that this will no longer be permissible, we are amending the second sentence of this paragraph to state that identification device distribution records must be entered by the person distributing the devices into the Tribal, State, Federal, or other database acceptable to each government entity.

Official Identification for Cattle and Bison (§ 86.4)

Section 86.4 concerns official documentation required for different species. As discussed earlier in this document, we proposed to revise § 86.4(a)(1)(i) to add the requirement that, beginning November 5, 2024, all official eartags sold for or applied to cattle and bison must be readable both visually and electronically.

Some commenters stated that allowing EID tags to be visually readable will fail to reduce, or will actually increase, human error as individuals would be transcribing 15-digit, rather than 9-digit, identification numbers, thus negating the intent of the rule.

We disagree that requiring EID tags to be visually readable will increase the likelihood of human error. The 15-digit identification numbers of the AIN numbering system currently used for all approved EID eartags begin with the same 6 digits: 840003. The first 3 digits of an AIN comprise the country code, which, for the United States, is 840. The following 3 digits, 003, signal that the animal has been identified using a sequential numbering system from a start number of 003,000,000,000. As a result, an individual visually reading an EID tag would only read 9 unique characters (the characters following 840003). These characters are comprised solely of numbers, whereas the 9-digit NUES numbers are alpha-numeric. Moreover, EID eartags have readability standards, while metal tags with NUES numbers do not. These include larger font size and color contrast. Given these comparisons of AIN numbers and NUES numbers, it is our view that transcription error is not likely to significantly increase from the current

state when relying on visual read of the eartag; if anything, several factors should make it easier, not harder, to transcribe the tag number. However, the use of EID tags would allow for an electronic read of the tag if a transcription error were believed to have occurred.

Some commenters asked for clarification about whether using brands as official identification would continue to be acceptable. Others stated that EID eartags should not replace brands as a means of official identification.

We proposed no changes to the regulations pertaining to, nor did we propose to restrict the use of, other methods of official identification for cattle and bison authorized by the regulations, which include ''brands registered with a recognized brand inspection authority and accompanied by an official brand inspection certificate, when agreed to by the shipping and receiving State or Tribal animal health authorities'' (9 CFR 86.4(a)).

Some commenters expressed preference for brands over eartags, claiming the former to be a more effective and reliable means of identification.

As stated above, this rulemaking does not discontinue brands as an official means of animal identification for cattle and bison. Brands registered with a recognized brand inspection authority and accompanied by an official brand inspection certificate remain an official means of identification for cattle and bison, if agreed upon by the shipping and receiving State.

Some commenters expressed concern about the retention rates of EID eartags that may fall off the animal or may be relatively easy to remove.

We do not agree that tag retention is a greater issue for EID tags than metal tags. APHIS-approved official identification tags undergo rigorous testing and trials to assure a retention rate of 99 percent (a loss of no more than 1 percent per year) and are intended for the life of the animal. While data on retention rates of metal NUES tags is lacking, field experience and anecdotal observation from regulators at the State and Federal level suggest that the retention rate of these metal tags is lower than our required retention rate of EID eartags. As one commenter mentioned, metal tags are not immune from potential problems, including tag loss, illegibility, and infection.

Almost all reported retention issues with EID tags are due to user error or use of unofficial tags intended for use for a shorter duration in feedlot cattle.

Regarding removal, it is unlawful to intentionally remove any official identification under current regulations in part 86. We proposed no change to this regulation.

A commenter interested in selling alternative identification devices that use Bluetooth and GPS technology stated that RFID tags are unreliable and subject to fraudulent use.

As stated above, approved official identification tags undergo rigorous testing and field trials to ensure they meet our high standards for efficacy. The regulations prohibit the fraudulent use and recording of official identification. Sections 86.3 and 86.4(d) and (f) outline requirements regarding recordkeeping, removal, and sale or transfer of devices.

Two commenters asked for an explanation of the protocol for replacing lost EID eartags.

Procedures for replacing any lost official identification devices are outlined in § 86.4(d) and remain unchanged as a result of this rulemaking.

Two commenters asked whether tags can be applied to animals directly by producers, or whether tags must be applied at approved tagging sites. One of these commenters stated that it should be permissible for producers to apply tags themselves.

Current regulations do not stipulate that the tags can only be applied at approved tagging sites. If a producer desires, they may purchase tags directly from a vendor and apply the tags to their own animals. In this case, the producer has no recordkeeping requirement regarding tag distribution.

Some commenters expressed concern that tags produced in foreign countries may compromise national security. Commenters also expressed concern that foreign-sourced tags could increase the vulnerability of the United States to supply chain sabotage.

Commenters provided no evidence to support the contentions that tags produced in foreign countries may ''compromise national security'' or increase the vulnerability of the United States to ''supply chain sabotage.'' However, all APHIS purchasing is compliant with all Federal contracting laws and regulations and with the Buy American Act (41 U.S.C. 8301–8303). This has always been true of contract purchasing by APHIS for the Animal Disease Traceability Program.

One commenter stated that PINs should not be a requirement to acquire and apply EID tags as that information can be gathered on other documents, such as health certificates.

The PIN is defined in 9 CFR 86.1 as a nationally unique number assigned by a State, Tribal, and/or Federal animal health authority to a premises that is, in the judgment of the State, Tribal, and/or Federal animal health authority a geographically distinct location from other premises. All currently approved EID eartags (RFID AIN ''840'' eartags) are associated with a PIN or a State location identification number (LID), inasmuch as a PIN or a LID is required for purchase of the tags (as stated in the OAIDS). A PIN is the numerical equivalent of a 911 postal address or a GPS number. A LID is the State-managed equivalent for producers who prefer to have the State store their information, rather than the Federal Government.

The commenter did not explain their specific concerns regarding PINs. That being said, we note that a PIN or LID is associated with the location where cattle are tagged, rather than the location of the cattle owner. Cattle may move to new locations that may have different PINs, LIDs, or new owners at will, but the PIN or LID associated with the location where the tag was placed on the animals remains specific to that location, thus facilitating traceback of the animals to that location when needed.

Health certificates cannot substitute for a PIN number because although information on health certificates include the location where the animal was loaded for interstate movement and destination location; they do not necessarily provide the location where a tag was placed on the animal.

Multiple commenters agreed with our decision to use language in the regulations to keep EID technology-neutral. Other commenters expressed support for their various preferred identification technologies, which included UHF, biometric, Bluetooth, and satellite geolocation. Commenters also asked whether high frequency or low frequency RFID tags would be the required or recommended standard.

We are neither requiring nor recommending any one type of EID eartag over another. Maintaining technological neutrality in the regulations will allow APHIS to adapt to technological developments and conduct animal disease traceability as rapidly and accurately as possible. So long as devices meet the standards, including for retention and safety, laid out in the OAIDS, and are readable both electronically and visually, they may be approved for use by APHIS. Producers will be able to decide which approved technology works best for them, based on their individual circumstances.

Some commenters stated that EID infrastructure should also support non-ADT uses.

EID infrastructure already supports non-ADT uses. For example, many dairies use EID tags to tie individual animals to production and management records. That information is separate from and not collected by the ADT program.

One commenter asked whether, in the event of an emergency, State departments of agriculture would be able to use orange EID tags typically used for heifer calves for other animals.

States are free to distribute any color of EID tag that is available. While orange tags are typically reserved for brucellosis vaccinates, this is not a requirement in the regulations.

Two commenters expressed concern regarding the purported difficulty of applying EID eartags. The commenters mentioned the difficulty of organizing tags not packed in sequential order and applying tags in cold conditions, as well as risk of fatigue and trauma to the hands.

The OAIDS provides guidance for packaging eartags, and states that packaging must maintain the tags in sequential order. The commenters do not provide evidence to support the implication that applying EID eartags is significantly more difficult in cold conditions or prone to causing fatigue and trauma to the hands than applying metal eartags or other forms of approved official identification, such as brands.

One commenter stated that the USDA should target tag distribution to cattle newly subject to the revised definition of *dairy cattle,* as it now includes beef/dairy cross bred cattle.

As noted in the economic analysis that accompanied the proposed rule, historically, APHIS has instructed dairy cattle operations that beef/dairy cross bred cattle should follow the same traceability regulatory requirements as purebred dairy cattle. Thus, official identification requirements applied to these animals prior to the implementation of this final rule and no targeted distribution is necessary.

One commenter stated that we should maintain the current use of AIN Device Managers to distribute official identification.

This final rule makes no changes to the current use of AIN Device Managers. Individuals may continue to distribute AIN devices by becoming AIN Device Managers. More information regarding this process can be found in the OAIDS.

One commenter volunteered to be a tag distributor for bison producers.

The commenter may reference the OAIDS document for further information on how to become an AIN Device Manager and distribute tags.

Several commenters stated that the regulations should specify that only 840-series, and not 900-series, EID tags may be used as official identification on domestic cattle because 900-series tags are not unique in their official identification. 840-series tags refer to EID eartags that begin with the prefix ''840'' and are manufactured using the AIN numbering system for the official identification of individual animals born in the United States. 900-series tags refer to eartags that begin with the prefix ''900,'' and are not manufactured for the official identification of individual animals in the United States, but are sometimes used by producers for individual livestock management purposes.

We believe the regulations already address the commenters' concern about the need for nationally unique numbers. Per the definition of official eartag, an official eartag is an identification tag that bears an official identification number. The regulations state that an official identification number is a nationally unique number that is permanently associated with an animal and adheres to the NUES system, AIN system, location-based number system, flock-based number system, or any other numbering system approved by the Administrator for the official identification of animals.

Currently, all APHIS-approved EID eartags available for domestic animals are manufactured using the 840-series AIN numbering system. 900-series tags do not meet the definition of an official eartag, as they do not bear an official identification number. Although 900-series tags may be suitable for non-ADT uses, they are not approved for use as official ID for animals born in the United States.

We disagree that the regulations should require the use of any specific numbering system. As stated in the proposed rule, this flexibility will allow for the possibility that different numbering systems may be developed and used in the future on EID eartags. Additionally, situations may arise that require the use of official ID that is not an 840-series tag. For example, cattle not born in the United States may have official identification from the country of origin or an alternate official ID approved by APHIS to designate a non-U.S. born animal. The NUES numbering system is also allowed under the regulations for official tags. Because NUES eartags applied to animals before November 5, 2024 will still be recognized as official for the lifetime of those animals, the NUES numbering format will still be in use for some time after that.

Several commenters encouraged the USDA to allow the use of all currently used EID tags as official identification for ADT purposes. Two commenters specifically asked that we allow 900-series tags to be used for official identification, as these tags are already used by some producers.

We disagree with the commenters. Nine hundred-series EID eartags currently used by producers for livestock management purposes do not fulfil the requirements of EID eartags approved by APHIS for official identification purposes. APHIS approves the use of EID eartags for official identification that meet certain standards for durability, efficacy, and safety. These standards are essential to ensuring that methods of official identification meet industry needs and are retained and effective for the purpose of traceability.

A 900-series tag could provide traceability for a single movement; however, because the tag is not associated with an official identification number, the initial distribution location and additional movements would not be tracked or readily available for officials performing disease traces. Additionally, other characteristics of the 900-series tags make them unsuitable for traceability. For example, it is illegal to remove 840-series tags, while there is no regulation preventing the removal, replacement, or reuse of 900-series tags.

One commenter asked whether official ID tags can be reused after the death of an animal.

Tags cannot be reused. A requirement of official identification tags is that they are unique and not reusable. This prohibition prevents an animal in a disease trace from being confused with another animal that should not be included in the trace.

One commenter stated that the proposed rule did not address the problem of retiring eartags of dead livestock and asked about protocol in such situations.

The commenter is correct that this proposal does not address tag retirement protocols. Expired cattle generally do not pose a high disease threat, although a lack of tag retirement data can pose challenges in disease traces if the final disposition of the animal is unknown. Retiring tags may become more feasible once EID is more commonly used for official identification. As this rulemaking would increase the use of EID, it may allow us to address this issue in the future.

Some commenters stated that electric and magnetic fields (EMFs) emitted by

RFID technology have the potential to harm humans and animals.

We do not agree with this comment. RFID tags are passive devices and do not emit EMFs. The Food and Drug Administration is not aware of any adverse health effects associated with RFID technology.

Several commenters asked us to require a specific placement and color for EID eartags for the sake of simplicity and uniformity.

The commenters do not provide evidence of the potential benefits of adding such a requirement. APHIS-approved official identification eartags are available in multiple colors from several manufacturers and vendors. The color orange is typically reserved by manufacturers for official EID tags to be used in official calfhood vaccinates for brucellosis, although the regulations do not require this. Otherwise, the color of the tags is at the owner's discretion. The placement of official RFID tags is recommended in the left ear, but there is no such regulatory requirement, and the tags may be placed in either ear at the owner's discretion.

One commenter stated that they have encountered problems finding the identity of cattle with EID eartags, as they were unable to obtain identifying information from the State about a stray bull found on a ranch that had an 840-series eartag for identification.

Producer data confidentiality is highly valued and protected. Availability of identifying information is limited to regulatory officials for the purpose of disease tracing activities and not available to the general public.

Several commenters asked that we address the issue of imported cattle that have lost their eartags. One of these commenters stated that they have encountered difficulties due to being unable to apply an 840-series tag to imported cattle that have lost their eartags.

It is not possible to tag animals born outside of the United States with 840-series tags as 840 is the country code for the United States. We recognize this is an issue and are working to provide an acceptable EID alternative for imported cattle that lose their official identification. However, this is outside the scope of this rulemaking.

Some commenters stated that branding as a method of official identification should be phased out, citing animal welfare concerns. One commenter stated that brands should not be used for animal disease traceability, but rather restricted to use for proof of ownership.

The scope of this rulemaking is limited to official eartags for cattle and bison. Other authorized forms of official identification, including branding, are outside the scope of this rulemaking.

One commenter stated that ''male'' parts of RFID tags should be more readily available from manufacturers, as these parts can fail.

APHIS is not aware of issues specific to ''male'' ends of RFID tags. APHIS recommends that anyone encountering such issues contact the relevant tag distributor or manufacturers, as manufacturers are required to report tag issues to APHIS.

Movement Within Slaughter Channels

The existing regulations in § 86.4(b)(1)(ii) allow cattle to move interstate to an approved livestock market and then to slaughter or directly to slaughter without official identification. Current § 86.4(b)(1)(ii)(C) stipulates that the cattle or bison must be identified if held for more than 3 days. The existing regulations are silent on identification requirements for slaughter cattle or bison that are not held at slaughter or held at slaughter for 3 or fewer days and then move to a new location.

To address this potential gap in traceability, we proposed to add paragraph (b)(1)(ii)(D) to § 86.4 to read as follows: ''Cattle and bison leaving a slaughter establishment may only be moved to another recognized slaughter establishment or approved feedlot and can only be sold/re-sold as slaughter cattle and must be accompanied by an owner-shipper statement in accordance with § 86.5(c)(1). Information listed on the owner-shipper statement must include the name and address of the slaughter establishment from which the animals left, the official identification numbers, as defined in § 86.1, correlated with the USDA backtag number (if available), the name of the destination slaughter establishment, or approved feedlot (as defined in 9 CFR 77.5) to which the animals are being shipped.''

This paragraph clarifies that the animals must stay within the intended terminal slaughter channels but may be moved to an additional slaughter plant or approved feedlot with appropriate documentation and identification.

Two commenters expressed their support for this proposed change, noting that it would expedite disease tracking.

Two commenters recommended improvements to the proposed new language in § 86.4(b)(1)(ii)(D) to allow cattle and bison leaving a slaughter establishment to be moved to a USDA-approved livestock auction (in addition to another slaughter establishment or feedlot).

We disagree with the commenters. Proposed paragraph § 86.4 (b)(1)(ii)(D) clarifies that animals may only move to another slaughter establishment or approved feedlot, with appropriate documentation and identification, and must remain in a terminal market. If animals were allowed to move from a slaughter facility to a livestock market for resale outside of the slaughter channel without official identification, they could circumvent the traceability regulations required for animals that would otherwise move interstate to a market, and thus become untraceable.

Multiple commenters asked us to add a definition of *slaughter channels* in order to provide clear regulations about other movements of cattle, including slaughter channel cattle not moving from points of sale to slaughter facilities in a timely manner; slaughter channel cattle being diverted from slaughter channels; and slaughter cattle moving to unapproved feed yards and holding pens. One commenter asked us to replace the phrase ''slaughter facility'' in § 86.4 with the term ''slaughter channel'' to clarify that livestock located anywhere in a slaughter channel are subject to the additional health and traceability requirements of the proposed rule.

We disagree with the commenters that a definition of *slaughter channel,* or a replacement of the term ''slaughter facility'' with the term ''slaughter channel,'' is needed, because any movement not specifically described as an exemption in § 86.4 requires the animals to meet all requirements for official identification. This includes the examples provided by the commenter if the cattle involved do not meet the requirements for the exemptions.

EID in Use of More Than One Official Eartag

Section 86.4(c) concerns situations in which the use of more than one official eartag is allowed. We proposed to remove references to visual-only eartags in this section.

Specifically, current paragraph (c)(3) of § 86.4 allows the application of a radio frequency identification or visual-only tag eartag with an animal identification number (AIN) having an 840 prefix to animals already tagged with NUES tags and/or brucellosis vaccination eartags. Because visual-only eartags will no longer be allowed as official identification under part 86, we proposed to revise this paragraph to state that a visually and electronically readable official eartag may be applied to animals currently identified with non-EID official eartags or vaccination tags.

We also proposed to remove § 86.4(c)(4), which states that a brucellosis vaccination visual eartag with a NUES number may be applied to an animal that is already officially identified with one or more official eartags. As a result of this rulemaking, the visual, *i.e.,* non-EID, brucellosis NUES tag would no longer be allowed as official identification under part 86, which eliminates the need for the paragraph.

A commenter expressed confusion about whether and why it was possible for an animal to have multiple forms of official identification.

Section 86.4(c) allows for the use of more than one official eartag in certain situations when the need to maintain the identity of an animal is intensified, such as for export shipments, quarantined herds, field trials, experiments, or disease surveys. Multiple forms of official identification are also allowed if an individual wishes to apply a visually and electronically readable official eartag to an animal that is currently identified with non-EID official eartags or vaccination tags. Our proposed rule did not include changes to the situations in which an animal is allowed multiple forms of official identification. To mitigate identification challenges associated with these situations, additional recordkeeping is required in these instances to ensure that adequate traceability is maintained.

Data Security

Many commenters expressed concerns related to data security and confidentiality. Commenters sought clarity about what data APHIS would collect when the requirement is implemented, where the data would be stored, and with whom it would be shared.

Commenters did not elaborate on their specific data concerns in great detail. APHIS takes care to protect personally identifiable information (PII) and proprietary business information in its recordkeeping, in compliance with the Privacy Act of 1974 (5 U.S.C. 552a).[15] Moreover, an EID tag is encoded with a number but no owner-specific information (*e.g.,* a number that identifies the animal, such as 840 001 018 932 052 or 42CXP9965).

We also note that APHIS and State animal disease traceability databases are not public databases. They are accessible only to Federal and State officials who meet strict permissions and security requirements; therefore, proprietary information will not be available to competitors or unauthorized individuals.

Some commenters expressed the view that producer information should be exempt from Freedom of Information Act (FOIA; 5 U.S.C. 552) requirements, in order to preserve the confidentiality of that information for producers.

We are making no change in response to the comments, as APHIS does not have the authority to define or redefine exemptions to FOIA. We can only apply FOIA consistent with the statute and caselaw.

That being said, we believe that there are adequate provisions in the law for the protection of confidential producer data. Some commenters appear to have the misconception that all information in Federal databases is available on request; however, FOIA and the Privacy Act each provide substantial protections for producer information, including the protection of financial and personal identifying information. Under FOIA, Exemption 4 protects trade secrets or commercial or financial information that is confidential or privileged; and Exemption 6 protects information that, if disclosed, would invade another individual's personal privacy. The Privacy Act protects personal information held by the Federal Government by preventing unauthorized disclosures of such information. Individuals also have the right to review such information, request corrections, and be informed of any disclosures. FOIA facilitates these processes.

Some commenters stated that the proposed rule does not adequately protect producers' data from potential cyberattacks or security breaches.

The commenters did not provide details regarding their specific concerns regarding these hypothetical threats. Both State and Federal databases undergo extensive security testing, restrictions, and permission for access to assure that only authorized individuals may access data. Both APHIS and States employ substantial teams of security and information technology experts to assure data security and integrity.

Commenters expressed differing views regarding where to keep animal identification data collected as a result of this rulemaking. Some commenters stated that a ''government'' or ''national'' database was needed, others stated that data should be held in State databases and shared with Federal officials when needed, while others stated that data should be kept in private databases to protect confidentiality.

Animal traceability data and disease information are kept in various Federal as well as State databases, with as-needed access restricted to the State and Federal officials responsible for managing high-impact diseases of the cattle industry. Device distribution records may also be stored in databases kept by producer organizations redistributing tags. As noted earlier, State and Federal databases undergo extensive security testing, restrictions, and permission for access, and both APHIS and State agencies employ teams of security and information technology experts to ensure data integrity and security.

One commenter stated that producers should have access to records of the animals produced on their farm after the animals leave the farm.

We disagree with the commenter, as this would compromise producer data confidentiality. Availability of information stored in APHIS and State animal disease traceability databases is limited to regulatory officials for the purpose of disease tracing activities.

One commenter stated that data integrity needs to be maintained when tags are retired and then reused.

Tags used for official identification are not reused.

One commenter stated that RFID technology can elicit and transmit information from clothing, appliances, and vehicles, placing personal information at risk.

The commenter provides no evidence to support this claim. RFID tags that are currently approved for official use by APHIS are passive tags. A passive tag is powered only by the reader emitting a radio signal, which allows the antenna within the tag to emit a signal back to the reader. There is no active power source within the tag, and the tag is unable to emit any signal without first being exposed to an RFID reader. There are no batteries associated with passive RFID tags.

Some commenters stated that data collection should be minimal, and access to it should be limited to animal disease traceability purposes.

APHIS agrees. Data collection required by this final rule is limited to the necessary information for adequate animal disease traceability. Access to animal traceability data and disease information kept in Federal and State databases is restricted to the State and Federal officials responsible for managing high-impact diseases of the cattle industry.

One commenter recommended APHIS make improvements to information

[15] See the systems of records notice for the animal disease traceability program, found at *https://www.regulations.gov/document/APHIS-2011-0057-0001.*

database systems to facilitate sharing of data between agencies.

The commenter did not detail specific improvements they believe should be made. Enhanced sharing of electronic information with appropriate permissions is one of the ADT program's goals. In the past, we have supported this goal by efforts such as funding electronic databases through cooperative agreements, and we intend to continue doing so as funding allows.

One commenter stated that the software available from APHIS is not user-friendly and asked us to provide software that will better meet the requirements of this rule.

We are unsure to what software the commenter is referring.

Legal Issues

A commenter stated that APHIS lacks authority to require the use of EID eartags, as the requirement does not directly and actively detect, control, or eradicate pests or diseases, nor is it an operation or measure such as ''drawing of blood and diagnostic testing'' authorized by 7 U.S.C. 8308.

The legal basis for this rulemaking is the AHPA, under 7 U.S.C. 8305, by which the Secretary of Agriculture may restrict the movement in interstate commerce of any animal, article, or means of conveyance if the Secretary determines that the restriction is necessary to prevent the introduction into or dissemination within the United States of any pest or disease of livestock. This authority is not limited to, as the commenter implies, the examples of ''drawing of blood and diagnostic testing of animals'' under 7 U.S.C. 8308. Moreover, 7 U.S.C. 8308 supports, rather than undercuts, this rulemaking; it provides the agency authority to ''carry out operations and measures to detect, control, or eradicate any pest or disease of livestock,'' including but not limited to diagnostic testing. Tracking via EID eartags is plainly a measure for these activities; it inherently facilitates them by allowing APHIS to quickly and easily identify livestock for the detection, control, or eradication of any livestock pest or disease.

One of these commenters further stated that APHIS lacked the authority to require EID tags because this requirement is not a valid prohibition or restriction in interstate commerce authorized by 7 U.S.C. 8305.

We disagree with the commenter. The Secretary of Agriculture is authorized by 7 U.S.C. 8305 to prohibit or restrict the movement in interstate commerce of any animal, article, or means of conveyance if the Secretary determines that the prohibition or restriction is necessary to prevent the introduction or dissemination of any pest or disease of livestock. The ADT program helps prevent the dissemination of disease by helping minimize the effects of disease outbreaks through restrictions, such as the EID eartag requirement, that the agency has determined are necessary for efficient livestock tracing.

We also note that this final rule does not require producers to purchase and affix EID eartags to their cattle as the only acceptable official identification device or method to meet the official identification requirements for interstate movement; the regulations continue to list eartags as one of several forms of authorized official identification, which also include tattoos and brands when accepted by State officials in the sending and receiving States.

Several commenters stated that the proposed rule violates the Tenth Amendment as certain States have codified into State law their own options for animal identification.

The Tenth Amendment provides that ''powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people.'' Regulating interstate commerce, which includes the interstate movement of animals, is a power delegated to Congress as an enumerated power under the Commerce Clause of the Constitution. Exercising this enumerated power through the AHPA, Congress has delegated to the Secretary of Agriculture the authority to restrict the movement in interstate commerce of any animal or article necessary to prevent the introduction into or dissemination within the United States of any pest or disease of livestock. The Tenth Amendment does not refute APHIS' authority to restrict the interstate movement of animals for this purpose and, in turn, displace a State's exercise of its regulatory power.

Two commenters stated that this rulemaking violated the intent of Article 1, Section 8, of the Constitution. One of these commenters stated that the USDA was falsely asserting that Congress has delegated and granted it broad powers which are implied, plenary, and inherent. The commenter noted that Congress has not mandated an electronic animal identification scheme, and therefore APHIS lacks the authority to impose one.

We did not assert that Congress has granted the USDA ''broad powers which are implied, plenary and inherent.'' Under the AHPA, Congress has delegated authority to the Secretary of Agriculture to promulgate regulations to prevent the introduction into the United States and the dissemination within the United States of any pest or disease of livestock. This rulemaking is consistent with Congress's clear, intelligible directive to protect animal health because it is intended to prevent the introduction and dissemination of livestock pests or diseases by improving the existing ADT program. USDA has issued this rulemaking based on Congress's grant of clear authority to it, not based on some implied or vague powers. Additionally, electronic animal identification represents a logical, modest update to the ADT program that is within USDA's mandate to implement.

Two commenters stated that this rulemaking violates the Fourth Amendment. One of these commenters stated that this was because requiring EID eartags constituted ''unconstitutionally seizing the cattle producers [sic] value-added information without compensation.'' The commenter also alleged that the rulemaking violates the Fifth Amendment because the ''value-added information associated with the mandatory EID eartags further constitutes the private property of the owner of the cattle.''

The requirement for official EID tags does not involve seizing a producer's value-added information. Some producers use EID eartags to participate in value-added verification programs overseen by the AMS. Producers may, but are not required, to use official EID eartags to participate in these verification programs and, alternatively, may also use 900-series tags. The premiums producers are paid for cattle participating in these verification programs are a result of the specific management practices required by said programs. While information regarding such management practices may be correlated with an animal's EID number, this information is kept in the hands of the producer; the producer's possession or use of the information is not interfered with at all, and, in any event, this information is not the same as the information collected for animal disease traceability purposes that is kept in State and Federal databases. Information correlated with an animal's EID number kept in State and Federal databases is limited to information necessary for disease tracing.

A commenter stated that this rulemaking violated Executive Orders 14005 and 14017 by requiring producers to purchase EID eartags manufactured in China. Another commenter stated that this rulemaking should adhere to Executive Order 14005 and be made in the United States.

Executive Orders 14005 and 14017 apply only to Federal Government purchases. APHIS abides by the Executive Orders and complies with the Buy American Act (41 U.S.C. 8301–8303).

We also note that this rulemaking does not stipulate that producers must purchase eartags made in a foreign country. APHIS approves official EID tags by any manufacturer, foreign or domestic, that fulfils the rigorous criteria listed in the OAIDS. Additionally, as noted earlier, eartags are one of several forms of authorized official identification. Producers who do not wish to use eartags may use another form of authorized official identification, such as tattoos and brands when accepted by State officials in the sending and receiving States.

Cost and Fairness

Many commenters opposed the proposed rule because of their belief that the cost of purchasing EID tags placed an undue financial burden on producers, particularly small farmers and ranchers. Commenters also claimed that these costs to producers would fuel consolidation in the livestock industry.

We do not agree with these comments regarding the magnitude of costs to the domestic cattle and bison industry, and do not think this rulemaking will result in further consolidation of the cattle industry. The commenters who raised these concerns often based them on the belief that official identification would be required for all or most cattle and bison regardless of whether they enter interstate commerce. Official identification is not required for all cattle or bison. Under the current regulations in § 86.4(b), which this final rule does not change, the following categories of cattle and bison are subject to official identification requirements for interstate movement: all sexually intact cattle and bison 18 months of age or over; all female dairy cattle of any age and all male dairy cattle born after March 11, 2013; cattle and bison of any age used for rodeo or recreational events; and cattle and bison of any age used for shows or exhibitions. Cattle and bison are exempted from official identification requirements if they are going directly to slaughter. Thus, large categories of cattle, such as feeder cattle or cull cattle going to slaughter, are not subject to the identification requirements. In addition, cattle and bison only require official identification under the regulations if they move interstate or are in Federal or State disease programs. Accordingly, many small producers will be exempted because they never move cattle interstate, so their cattle do not require official identification.

While we acknowledge the commenters' concern over consolidation of the cattle industry, we disagree that an EID tag requirement would cause consolidation. Data from USDA's National Agricultural Statistics Service reflect consolidation as a broader trend in the cattle industry that is present in both States that have and States that have not implemented a State-specific EID tag requirement.

That being said, we acknowledge that producers may at some point have to assume costs associated with purchasing EID tags as a result of this rulemaking. Accordingly, we have prepared a regulatory impact analysis (RIA) that estimates aggregate annual costs to the domestic cattle and bison industry as a result of the rule. The analysis estimates, conservatively, that 11 million cattle and bison are tagged with visual official identification per year to fulfill official identification requirements under the regulations. This number represents approximately 11 percent to 12 percent of the cattle and bison in the domestic inventory. We estimate that these are the average percentages of cattle that would be required to have EID tags instead of visual-only tags each year under this rule. The cost is estimated to be approximately $26.1 million, assuming no Federal funding is provided. (APHIS has historically provided funding for EID eartags and intends to continue doing so as long as funding is available. Funding is discussed in greater detail later in this document.) This equates to an average cost of $30.45 per cattle or bison operation each year; or based on total industry cash receipts from 2021, approximately 2.5 cents per $100 (0.025 percent).

The RIA also articulates the benefits of increased traceability that were previously identified in the economic analysis that accompanied the 2013 final rule establishing the regulations, particularly the foregone liabilities when traceability is not quick or accurate, and delineates how EID furthers the aims of efficient and accurate traceability that undergird the regulations. The RIA for this final rule is available on *Regulations.gov* as a supporting document for this final rule, as well as by contacting the individual listed below **FOR FURTHER INFORMATION CONTACT**. For reasons discussed in the 2013 economic analysis and the RIA that accompanies this final rule, it has been and continues to be APHIS' position that the benefits associated with timely and accurate animal traceability significantly outweigh costs to regulated entities.

Many commenters stated that the rule unfairly favors large corporations over small producers. It was stated that small producers would have to pay more to comply with the regulations than large operations due to bulk discounts offered by EID tag manufacturers. Other commenters stated that large corporations were favored because they are allowed to use GINs to officially identify their animals.

The commenters are correct that many EID tag manufacturers currently offer lower rates for EID tags bought in bulk. The calculations for the average price of an EID tag in the RIA factor in these price differences. As noted previously, most small producers will not be affected by this rulemaking because they do not move their cattle interstate. Small producers that are affected by this rulemaking may consider creative ways to capitalize on bulk discounts for EID tags, such as cooperative buying. These would be individual business decisions based on producer's unique circumstances. We also note that, while APHIS cannot commit to long-term funding for EID tags because the availability of Federal funding in future fiscal years is dependent on annual Congressional appropriations and USDA–APHIS budgetary priorities, APHIS has provided these tags free of charge since 2020. Funding for EID eartags is discussed in greater detail later in this document.

This rulemaking does not change the regulations regarding the use of GINs. Methods of official identification other than official eartags are outside the scope of this rulemaking.

Some commenters stated that this rulemaking would force small operations out of the livestock market and thus undermine the resiliency of the nation's food system.

We disagree that an EID requirement undermines efforts to build and maintain a resilient food supply. For the reasons discussed earlier in this document, many small producers will not be affected by this rulemaking. A resilient food supply relies on the health and wellbeing of our nation's livestock, which is the intended outcome of an effective and efficient ADT system.

Some commenters stated that this rulemaking is designed to benefit export markets by making it easier for companies to ''ship products around the world'' or by protecting international trade markets, at the expense of small producers who will bear the cost of the rulemaking.

We acknowledge possible benefits to export markets and trade associated

with domestic animal disease traceability and EID—these are referenced in the RIA that accompanies this final rule. We disagree, however, that this final rule is intended to directly benefit cattle and bison exporters. This final rule pertains to interstate movement of cattle and bison, not the export of cattle and bison, and foreign markets are free to set their own import requirements. While it is true that many of these requirements currently include EID, that is not within APHIS' purview. Furthermore, options already exist for exporters to meet any such requirements; many exporters currently use third-party verification programs under the purview of AMS to comply with traceability requirements of export markets.

Commenters stated that costs to producers extended beyond the cost of EID tags, and included infrastructure such as EID readers, software, and labor. A commenter stated that this rulemaking would require additional labor for accredited veterinarians to enter data into a database, the cost of which would be passed on to producers. It was stated that our RIA was flawed because it did not take these costs into account.

We disagree with the commenters. The official identification requirement does not require the producer to have hardware (readers) or software (computer systems). Readers and software are not required because each EID tag also has a visual component. The tag number is imprinted on the plastic shell containing the EID portion of the tag. The tags can thus be used in the same manner as visual tags by producers who do not wish to invest in tag-reading hardware and software.

We disagree that this final rule requires producers to incur additional labor costs related to application of tags because the regulations already require the placement of official identification. The EID requirement only changes the type of eartag that must be used for cattle that require official identification and that are officially identified using eartags. The labor involved in applying a metal NUES eartag should not be any more burdensome than the labor involved in applying an EID eartag.

Likewise, this final rule imposes no new requirement for accredited veterinarians to enter data into a database. Accredited veterinarians may continue collecting the information already required by the regulations in their medical records in the same way they currently do, so long as the records are retrievable when a disease outbreak occurs. Costs passed on to the producer should only reflect the difference in the cost of tags because this final rule does not require any additional labor.

Some commenters stated that APHIS should acknowledge that EID tags are meant to be read electronically and update the RIA to account for the cost of readers.

APHIS disagrees that EID tags are meant to be read only electronically. As explained above, EID tags must be readable both electronically and visually. To ensure the visual readability of eartags, the OAIDS requires that EID tags be readable from 30 inches with 20/20 vision, while there was no readability standard for metal NUES tags.

Two commenters stated that mandatory EID may increase corporate control over the livestock industry by giving packers more information about how animals are produced.

APHIS-approved official eartags only encode the 15-digit animal identification number. They do not encode any producer information.

Many commenters noted that APHIS has provided funding for EID eartags in the past and stated that the agency should commit to continuing this funding. Some commenters specified that funding should be provided for at least the first 2 years after the final rule's implementation. Commenters also stated that APHIS should provide funding for necessary equipment and related costs, such as readers, data management systems, and labor.

Since 2020, APHIS has provided funding for EID eartags, as well as readers and ear taggers. Since the availability of Federal funding in future fiscal years is dependent on annual Congressional appropriations and USDA–APHIS budgetary priorities, a long-term commitment to this funding is not possible. We intend to continue to provide assistance as long as funding is available. However, in the absence of Federal funding, producers would have to assume costs associated with purchasing EID tags. For this reason, we have prepared an assessment that estimates annual aggregate costs to the domestic cattle and bison industry associated with this rule.

As noted earlier, this final rule does not require producers or livestock markets to have electronic reading equipment or additional data management systems, because the official EID tags must be readable visually as well as electronically. Producers may continue using EID eartags the same way they currently use non-EID, visual-only eartags.

Finally, for the reasons discussed earlier in this document, we disagree that this rulemaking will cause producers to incur additional labor costs. The application of an EID eartag should not result in more labor costs than the application of a non-EID eartag.

Two commenters stated that the USDA should continue funding States via cooperative agreements. A commenter stated that funding for States to support ADT infrastructure should be increased.

This final rule does not impact the ADT annual cooperative agreements with States, Territories, or Tribes. We note that this funding is separate from the additional funding that APHIS has provided since 2020 to support EID tags and infrastructure. APHIS intends to provide funding for EID eartags and infrastructure for as long as funding is available, but we are unable to commit to multi-year funding for the reasons discussed above.

Two commenters stated that the RIA was inaccurate in its statement that the cost of tags would increase from $3.3 million annually (the estimated cost of metal NUES tags) to $29.3 million annually (the estimated cost of EID tags), as APHIS has been providing metal NUES tags to producers at no cost.

The commenter is correct that APHIS has provided NUES eartags at no cost to producers. The commenter fails to acknowledge, however, that APHIS has also been providing EID tags at no cost to producers since 2020. The estimates in the RIA take into account that funding for neither type of tag has been guaranteed in the past, nor can funding for EID tags be guaranteed in the future, as this funding depends on each year's Agency budget and competing disease priorities.

Two commenters stated that the estimates for the annual cost of EID eartags in the RIA were flawed because they only accounted for costs to animals currently being identified by non-EID tags. The commenters stated that the estimated number of affected animals did not consider animals currently tagged with EID tags, or animals that are required to have official identification but are not in compliance with the regulations.

Cattle and bison already identified with official EID eartags are already in compliance with this final rule, and therefore would not incur new expenses as a result of it. While we recognize that some people may not comply with the current regulations regarding official identification, we have no means of estimating their number. We also note that people currently not in compliance with the regulations are unlikely to begin complying as a result of this rulemaking, and therefore would not

increase demand for official identification tags.

A commenter stated that the RIA does not include information about the estimated economic impact for individual operations.

The commenter is incorrect. The RIA states that, assuming the Federal Government does not provide tags free of charge in the future, the average cost per operation to purchase EID eartags would range from $26.24 to $29.45 for FDX eartags, and from $31.13 to $34.73 for HDX eartags.

A commenter stated that our cost estimates did not consider costs incurred for livestock moved interstate after purchased at an in-State general auction market. The commenter asked whether the buyer would be charged for the cost of eartags or be required to place official eartags on the animals they purchased.

Under the current regulations in § 86.4(b), which this final rule does not change, cattle and bison that are required to have official identification must be officially identified prior to interstate movement unless they are exempted from the requirement for official identification. Animal classes and movements that currently require official identification will continue to require official identification, while animal classes and movements exempted from the official identification requirements will continue to be exempted.

A commenter stated that we should adjust the estimate of impacted cattle in the RIA to account for the expanded definition of dairy cattle.

We disagree with the commenter. APHIS has not expanded the definition of dairy cattle. The change to the definition of *dairy cattle* is a codification of guidance that APHIS has consistently given to producers and State animal health officials, and not a change in policy. Beef/dairy cross breeds should already be officially identified. We have no indication of noncompliance or controversy surrounding this policy. Assuming regulated parties are in compliance, beef/dairy crosses are already accounted for in our estimate of 11 million impacted cattle.

We acknowledge the possibility that there may be cattle producers that did not consider their beef/dairy cross breeds to be dairy cattle, and were alerted to our interpretation of the definition of dairy cattle to encompass beef/dairy cross breeds by this rulemaking. However, as we have no indicators of widespread noncompliance, we expect this scenario to be rare and expect the number of cattle to be affected by it to be de minimis.

A commenter asked why the RIA did not report on tracing exercises using branded cattle.

While the regulations allow the use of brands to fulfil the requirements for official identification if agreed upon by sending and receiving States, brands do not uniquely identify an animal and are not intended for animal traceability. Brands are not unique outside of local areas, are currently only used in 14 States, and are not systematically recorded in national databases. For these reasons, tracing exercises are restricted to animals identified with AIN 840-numbered tags and NUES tags.

A commenter suggested further cost-benefit analysis to assess the impact on cattle and bison producers while ensuring maximum expansion of ADT capability.

The commenter did not specify what they believe our analysis is lacking. We believe the RIA comprehensively assesses the costs and benefits of this rule.

Some commenters disagreed with our estimation that the number of impacted cattle would be 11 million. A commenter stated that, previously, the USDA estimated that the final rule would impact 30 million cattle that cross State lines annually. Another commenter stated that many State identification programs are tied to the Federal system, and therefore even cattle that do not cross State lines would be impacted by this rulemaking.

The commenter is mistaken that we previously estimated this rulemaking would impact 30 million cattle, and the commenter provides no source for this figure. Our estimate of 11 million cattle is based on the number of official identification tags that have been used in previous years. Many animals that move interstate are exempt from official identification requirements, such as beef cattle under 18 months of age, and animals going to slaughter or to an approved livestock market.

Regarding the concern about State identification programs, APHIS is unaware of any intrastate movement requirements that may mimic Federal regulations. Moreover, intrastate movement regulations are beyond our jurisdiction.

A commenter stated that the RIA uses outdated 15-year-old data to determine that many small entities would not be affected because most small entities market through local auctions. The commenter stated that this is no longer necessarily the case, as small entities have increased their use of online livestock video auctions and alternative livestock marketing channels that would require the use of an EID tag. The commenter also stated that market consolidation has reduced the available number of livestock auctions, forcing some small producers to market outside their state.

The RIA uses NAHMS data from 2008 as well as from 2017 to determine that small operations are less likely to move cattle interstate. Data from the 2008 NAHMS report indicated that 82 percent to 88 percent of beef cattle were marketed through general auction markets. These markets tend to be in-state auctions or out-of-state APHIS approved markets, for which official identification is not required. Data from the 2017 NAHMS report further indicated that small operations were most likely to use auction markets, while larger producers used auctions as well as other marketing channels. Although the published literature on small sized farms moving cattle interstate is scarce, we believe the data from these reports are still applicable and relevant. We are not aware of any significant change in marketing practices for small producers.

Furthermore, we disagree with the commenter that small producers are forced to market out of State due to market consolidation, as the number of APHIS-approved livestock markets has increased steadily each year. In 2013, when the ADT rule was implemented, there were 703 active APHIS-approved markets; today there are 1,310.

A commenter stated that a calculated benefit of $30 million per year is inaccurate, as the calculation is based on incorrect assumptions that EID eartags will reduce the time to detect an outbreak, reduce herd surveillance costs, improve practices that identify diseased cattle, and reduce the probability of countries imposing trade restrictions because of a disease outbreak in cattle.

APHIS would like to clarify the commentor's misunderstanding. Thirty million dollars was our estimate of the additional cost of EID tags; we assessed, but did not quantify, expected benefits.

Although use of EID would not reduce the time it takes to initially detect a disease or conduct surveillance, EID reduces the time to find diseased and exposed animals. APHIS disease investigations are often concluded through quarantine and testing or depopulation of cattle herds when the animal of interest is not identifiable, which incurs costs for livestock producers as well as APHIS. As explained in the RIA, when outbreaks of livestock diseases occur, the use of EID eartags can help limit their size and

scope, thus reducing the number of animals that are depopulated, the impact to producers and communities, and the probability that trade restrictions are imposed. Additionally, rapid containment of foreign animal diseases and identification of affected, exposed, and vaccinated animals will expedite the return of export markets, should they close in the event of a disease outbreak.

A commenter stated that, because only approximately eight manufacturers have had their EID eartags approved for official use by APHIS, this rulemaking creates an oligopoly of eartag manufacturers on which producers are forced to rely.

This rulemaking does not in any way restrict new manufacturers from applying for approval of their eartags for use as official identification. In fact, changes proposed in this rulemaking streamline the approval process for new EID devices in order to encourage new manufacturers to enter the market. APHIS will continue to approve official identification tags from new companies that are in compliance with our regulations.

A commenter stated that producers need assurance that eartags and related infrastructure will be available at a reasonable price.

APHIS will continue to approve eartags for official identification. As noted earlier, this final rule does not require the use of infrastructure, such as readers, because tags are required to have a visual component.

A commenter asked us to include an assessment of biometric tools for official identification that have the potential to reduce costs per head of cattle.

The RIA includes in its assessment the types of EID eartags that are currently approved for use, which include FDX and HDX RFID tags. APHIS would consider any type of alternate EID methods that are supported by credible research.

Two commenters stated that future new EID technologies mentioned in the proposed rule could result in higher costs for producers.

The RIA estimated costs to producers based on EID technology available and approved for use today, which is currently limited to RFID. In the proposed rule, we stated that we refer to EID, rather than RFID, tags in the regulations in order to allow for other electronically readable technology, should it become available in the future. Just as referring to EID would not limit official eartags to the technology available today, it would also not limit official eartags to a hypothetical higher-cost technology available in the future. Maintaining technological neutrality in the regulations provides flexibility for the regulated community to choose the technology that best meets their individual needs, cost being one consideration.

Some commenters stated that ADT raises fear of market manipulation by multinational packing corporations or the government.

The commenters did not elaborate on their specific concerns regarding market manipulation and provided no supporting evidence of this hypothetical situation. As discussed earlier in this document, APHIS protects personally identifiable information (PII) and proprietary business information in its recordkeeping.

A commenter stated that the requirement for ICVIs is an added expense.

The commenter is incorrect. Cattle and bison to which official identification requirements apply are already required to be accompanied by an ICVI or alternate movement document before moving interstate. We did not propose to substantively change any regulations pertaining to ICVIs. Rather, we proposed to make an editorial change to the definition of ICVIs to account for the use of electronic ICVIs in addition to paper ones.

A commenter stated that this rulemaking will result in the elimination of incentive programs that encourage producers to adopt EID, which may have been the only way some producers could afford the technology.

We believe that the ''incentive programs'' to which the commenter is referring are the verification programs overseen by AMS. We disagree that this rulemaking will necessarily eliminate these verification programs. Verification programs can fulfill trading partners' requirements for traceability from birth to slaughter as well as additional recordkeeping requirements for exported cattle. Because the current regulations and this rulemaking do not fulfil these requirements, we expect continued need for verification programs.

Miscellaneous

There were a number of comments that did not fall into any of the categories listed above.

A commenter asked for clarification on the meaning of preemption language in § 86.8 and the preemption language mentioned in the proposed rule relevant to Executive Order 12899 (sic).

Section 86.8 provides that States and Tribes may not specify an official identification device or method for interstate movement if the regulations allow for multiple devices or methods, nor may a receiving State or Tribe impose requirements that would require the shipping State or Tribe to develop a particular type of system or alter an existing system in order to meet the requirements. There was no Executive Order 12899 language in the proposed rule; however, we believe the commenter is referring to Executive Order 12988, which was referenced, and transposed the numbers. The 12988 language in the preamble of the proposed rule, in contrast, has the effect of stating that, if finalized, State laws that conflict with the specific provisions of this rulemaking would be preempted. For example, a State's animal identification regulations could not continue to allow for non-EID forms of official identification of cattle and bison that are subject to the ADT regulations.

We emphasize that the regulations in part 86 apply only to interstate movement; States may develop their own official identification requirements for intrastate movement that apply after an animal arrives from a shipping State or may otherwise impose in-State requirements for the cattle once the movement has occurred.

The same commenter asked whether a State could impose official identification importation requirements for classes of animals otherwise exempt in the ADT rule.

The final rule [16] that established § 86.8 indicated that States may require the official identification of classes of animals that are exempt under our regulations, provided that the receiving State's requirement does not require the shipping State to develop a particular type of system or alter an existing system.

The same commenter asked whether a State could restrict the types of official identification devices required for imported animals when the ADT rule permits additional approved methods of identification for the species, such as restricting the use of GINs for the movement of pigs and instead requiring individual animal IDs. The commenter asked us to amend the regulations to allow a State to impose these additional requirements if they are not currently permissible.

Because the current regulations allow for group or lot identification as a means of official identification, restricting the use of GINs and requiring individual animal ID for pigs, or cattle or bison as applicable to this rulemaking, is prohibited under § 86.8.

[16] See footnote 1.

Amending § 86.8 as requested is outside the scope of this rulemaking, and one of the amendments requested by the commenter goes against the stated aims of the ADT program.

Finally, the same commenter asked us to explain the enabling legislation for § 86.8.

The enabling legislation for § 86.8 is the AHPA.

Two commenters stated that this rulemaking would reduce the speed of commerce. Conversely, another commenter stated that EID allows for the collection of animal movement data at the speed of commerce.

We disagree with the commenters who stated the rule would reduce the speed of commerce. EID and electronic records have the potential to increase the efficiency and speed of routine operations in the cattle and bison industry. EID tags allow staff to read animals' identification numbers without having to restrain or handle the cattle or bison. For cattle or bison requiring ICVIs, electronic tags also allow veterinarians to rapidly and accurately complete health certificates and movement documentation without slowing the speed of commerce.

One commenter asked that we amend § 86.5(c)(7)(i) to require that the official identification numbers of cattle and bison are recorded during the transfer from an approved livestock facility directly to a recognized slaughtering establishment.

We will consider the commenters' suggestion; however, this is outside the scope of this rulemaking.

One commenter asked us to state that forms used for interstate poultry movement must meet the same accuracy and clarity criteria that pertain to ICVIs for poultry and other species.

We will consider the commenters' suggestion; however, this is outside the scope of this rulemaking.

One commenter asked us to create a standardized ICVI form.

This is outside the scope of this rulemaking. We note that all ICVI forms are required to contain the same information, which is listed under the definition of *interstate certificate of veterinary inspection (ICVI)* in § 86.1.

One commenter stated that this rulemaking could reduce the use of the brucellosis vaccine because the use of EID tags would double the cost of brucellosis vaccination.

APHIS requires brucellosis vaccination for cattle in the Greater Yellowstone Area. Cattle that are vaccinated for brucellosis are required to have official identification and currently use metal official NUES tags. While we acknowledge that EID tags are more expensive than metal NUES tags, and discuss these differences in cost in the RIA, we disagree with, and the commenter provides no evidence to support, the speculation that these costs would discourage compliance with the requirement for brucellosis vaccination.

Some commenters asked us to remove the requirement to tattoo animals that receive the brucellosis vaccine because correct placement of an EID eartag makes tattoo placement difficult.

We disagree with the commenters that EID tag placement interferes with brucellosis tattoo placement. While official EID tags may be placed in either ear, the recommended placement is the left ear to avoid interference with the brucellosis tattoo, which is required on the right ear.

One commenter stated that additional education regarding proper tag application and retention for veterinarians and producers is necessary.

APHIS agrees that education assists in proper tag application and increased tag retention. We support education through efforts such as cooperative agreements and outreach and intend to continue such efforts as funding allows.

One commenter asked for guidance stating that exports from the United States to Canada will clearly state requirements for use of an approved indicator with the International Organization for Standardization (ISO) 11784.

The final rule does not pertain to the export of livestock. Requirements for exported livestock are found in 9 CFR part 91.

One commenter asked us to establish performance standards for the retention of backtags referenced in § 86.4(b)(1)(i)(C).

Backtags are not methods of official identification but are mentioned in § 86.4(b)(1)(i)(C), in the context of an exemption for cattle and bison that are moved interstate from the requirement of official identification if certain conditions are met. The existing regulations require that backtags used to fulfil this exemption must ''ensure that the identity of the animal is accurately maintained until tagging.'' We believe this adequately addresses the required performance of backtags used in this context.

Two commenters stated that the use of alternative movement records should be increased, and that these alternative movement records could be created by a veterinarian or their designee, but APHIS should not require an inspection or attestation of health by a veterinarian.

The existing regulations in § 86.5(a) already provide for alternatives to the ICVI for animals moving interstate. Alternate documentation requires an agreement between both shipping and receiving States to be considered official movement documentation. The current regulations do not specify that an alternative movement document requires an inspection or attestation of health by a veterinarian.

Two commenters stated that the USDA and States should target enforcement of ADT requirements beyond fixed-facility livestock auction markets to avoid incentivizing direct selling outside of markets.

We do not believe this rulemaking will incentivize direct selling outside of markets. Compliance with the regulations in 9 CFR part 86 is required for animals subject to these regulations, regardless of whether the animal is sold through a livestock market or a private sale. Accredited veterinarians responsible for inspection and interstate movement of animals are subject to the same requirements and face the same sanctions for noncompliance, regardless of whether they work for or from a market or private treaty sale. Accredited veterinarians must submit copies of the documentation (ICVI or alternate movement documents) to the origin and destination State official within 7 days of inspecting the animal, and they must complete this documentation accurately and completely. Accredited veterinarians that are non-compliant are subject to sanctions including monetary penalties, loss of accreditation, and, in some cases, criminal penalties.

A commenter asked whether there will be civil or criminal penalties for not adhering to the requirements of the final rule.

The AHPA lists criminal and civil penalties relevant to violating the requirements of the regulations in section 8313. Changes to the regulations do not impact the Act.

Some commenters stated that this rulemaking could subject cattle producers to liability, should the animal bearing their EID eartag contract a disease after the animal is sold or should food safety issues arise in meatpacking plants.

Under this rulemaking, producers are not liable for disease infection after an animal leaves their premises. The EID requirement thus has no known implications for producer liability.

One commenter claimed that the reason behind requiring EID for eartags is the Global Roundtable for Sustainable Beef.

The commenter provided no evidence to support this claim. As explained in the proposed rule and earlier in this document, the purpose of this action is

to improve our animal disease traceability program's ability to trace animals accurately and rapidly in order to aid us in disease response.

Several commenters requested that APHIS seek equivalency from trading partners by requiring imported cattle to have EID.

The scope of this rulemaking is limited to requirements for domestic cattle in interstate commerce. New requirements for imported cattle would require a separate rulemaking.

Some commenters stated that the ADT program needs to be compatible with the general traceability principles of the World Organization for Animal Health (WOAH).

We are unsure of what specific principles the commenters are referring to. However, we note that, as a WOAH member country, the United States contributes to development of, and complies with, the guidelines that the member countries develop.

Finally, we note that we are making non-substantive editorial changes to the OAIDS to improve clarity, readability, and accuracy. This includes changes such as reordering information, removing duplicative information, and removing broken links. It also includes editing to a paragraph explaining which criteria manufacturers must meet for low-frequency devices. The edits remove a sentence stating that substantial sales data or approval in another country may be considered in lieu of International Committee on Animal Recording's (ICAR) materials/environmental testing. We are making this edit because sales data or approval in another country may not be an adequate substitute for ICAR testing, and we do not have a standard for what ''substantial sales data'' means. The revised OAIDS is published alongside this final rule.

Therefore, for the reasons given in the proposed rule and in this document, we are adopting the proposed rule as a final rule, with the changes discussed in this document.

Executive Orders 12866, 13563, and Regulatory Flexibility Act

This final rule has been determined to be significant for the purposes of Executive Order 12866, as amended by Executive Order 14094, ''Modernizing Regulatory Review,'' and, therefore, has been reviewed by the Office of Management and Budget.

We have prepared an economic analysis for this final rule. The economic analysis provides a cost-benefit analysis, as required by Executive Orders 12866 and 13563, which direct agencies to assess all costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, and equity). Executive Order 13563 emphasizes the importance of quantifying both costs and benefits, of reducing costs, of harmonizing rules, and of promoting flexibility. The economic analysis also examines the potential economic effects of this final rule on small entities, as required by the Regulatory Flexibility Act. The economic analysis is summarized below. Copies of the full analysis are available on the *Regulations.gov* website (see footnote 6 in this document for a link to *Regulations.gov*) or by contacting the person listed under **FOR FURTHER INFORMATION CONTACT**.

We are amending the animal disease traceability regulations to recognize only eartags that are both visually and electronically readable as official eartags for use for interstate movement of cattle and bison that are covered under the regulations. We are also clarifying certain record retention and record access requirements. These changes will enhance the ability of State, Federal, and private veterinarians, and livestock producers, to quickly respond to high-impact diseases currently existing in the United States, as well as foreign animal diseases that threaten the viability of the U.S. cattle and bison industries. The benefits of animal disease traceability include enhancing the ability of the United States to regionalize and compartmentalize animal health issues, minimizing the costs of disease outbreaks, and enabling the reestablishment of foreign and domestic market access with minimum delay following an animal disease event.

APHIS conducted a cost-benefit analysis to determine how the transition to electronic identification (EID) tags will affect the cattle and bison industries. Our analysis suggests that approximately 11 million cattle are currently tagged with official non-EID eartags per year. The rule will not change the number of cattle tagged, but it will increase the estimated average annual cost of purchasing tags by approximately $26.1 million dollars per year, or $30.39 per cattle or bison operation. As noted in APHIS' cost-benefit analysis, the cost of purchasing new tags is the only additional costs APHIS has determined will be imposed on producers, regardless of whether they currently own electronic reading equipment.

We began soliciting comments concerning the proposal for 60 days, ending March 20, 2023. In response to several requests by commenters, we extended the comment period by 30 days, to April 19, 2023. We received 2,006 comments from industry groups, producers, veterinarians, State departments of agriculture, and individuals. While many of these comments were in support of the proposed rule, we did receive concerns regarding the economic impacts of this rule. Comments included concerns regarding the potential additional costs of having to adhere to the new EID technology, beyond the cost of the EID tags, along with concerns that this rulemaking will disproportionately impact small businesses. We have evaluated these concerns carefully and, while the new EID tags will increase the costs of identifying certain cattle and bison as outlined in this analysis, we have found the other concerns to be unsubstantiated, which we discuss in the cost section of this analysis.

Radio frequency identification (RFID) technology, a type of electronic identification, has been available in the livestock industry for many years. APHIS has evaluated the cost structure of current RFID technologies, commonly known as FDX and HDX. Both technologies work well and have similar qualities. This report describes the cost structure of these EID eartags. We provide 10 years of historic population levels for cattle and bison in order to provide the reader with a range of cost estimates based upon a fluctuating cattle and bison population.

EID eartags are a vital component to efficient and accurate traceability of cattle and bison. It benefits stakeholders by significantly reducing the numbers of animals and response time involved in a disease investigation.

One of the most significant benefits of the rule will be the enhanced ability of the United States to regionalize and compartmentalize animal disease outbreaks. Regionalization is the concept of separating subpopulations of animals to maintain a specific health status in one or more disease-free regions or zones. This risk-based process can help to mitigate the adverse economic effects of a disease outbreak. Traceability of animals is necessary to form these zones that facilitate reestablishment of foreign and domestic market access with minimum delay in the wake of an animal disease event. The use of EID eartags can significantly reduce the amount of time it takes animal health officials to complete a trace investigation, which involves knowing where diseased and potentially exposed animals are, and where they have been. Animals that may have come

in contact with an affected animal can number in the thousands or tens of thousands. Transitioning from visual to electronic identification devices may significantly reduce the time it takes animal health officials conducting a trace to scan animals in a herd during a disease response. The more efficiently and effectively animal health officials can complete a trace, the faster we can regionalize and compartmentalize animal disease outbreaks in order to mitigate adverse economic impacts. Having an EID system in place will, therefore, minimize not only the spread of disease but also the trade impacts an outbreak may have.

Executive Order 12372

This program/activity is listed in the Catalog of Federal Domestic Assistance under No. 10.025 and is subject to Executive Order 12372, which requires intergovernmental consultation with State and local officials. (See 2 CFR chapter IV.)

Executive Order 12988

This final rule has been reviewed under Executive Order 12988, Civil Justice Reform. This rule: (1) Preempts all State and local laws and regulations that are in conflict with this rule; (2) has no retroactive effect; and (3) does not require administrative proceedings before parties may file suit in court challenging this rule.

Executive Order 13175

This final rule has been reviewed in accordance with the requirements of Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Executive Order 13175 requires Federal agencies to consult and coordinate with Tribes on a government-to-government basis on policies that have tribal implications, including regulations, legislative comments or proposed legislation, and other policy statements or actions that have substantial direct effects on one or more Indian Tribes, on the relationship between the Federal Government and Indian Tribes or on the distribution of power and responsibilities between the Federal Government and Indian Tribes.

APHIS has determined that Executive Order 13175 is applicable to this rulemaking and that therefore consultation is required, as this final rule may affect one or more Tribes and the cost associated with managing cattle and bison herds. To raise awareness of this rulemaking, APHIS hosted an informational webinar to Tribal nations on October 27, 2021, to notify Tribes of this rulemaking and solicit consultation. On May 18, 2022, the APHIS Office of National Tribal Liaison sent letters to all 574 Tribal Leaders inviting them to attend an upcoming Tribal listening session. The listening session was held on June 23, 2022. Sixteen individuals attended, and we did not receive feedback that substantively affected the development of this rulemaking. APHIS will work with the Office of Tribal Relations to ensure that additional outreach occurs in 2024. If a Tribe requests consultation, APHIS will coordinate with the Office of Tribal Relations to ensure that meaningful consultation occurs.

Paperwork Reduction Act

In accordance with section 3507(d) of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the reporting, recordkeeping, and third-party disclosure requirements described in this final rule are currently approved by the Office of Management and Budget (OMB) under OMB control number 0579–0327. The categories of burden and numbers haven't changed as a result of this rule. The last approval from 2021 (*https://www.regulations.gov/document/APHIS-2021-0056-0001*) is still accurate.

E-Government Act Compliance

The Animal and Plant Health Inspection Service is committed to compliance with the EGovernment Act to promote the use of the internet and other information technologies, to provide increased opportunities for citizen access to Government information and services, and for other purposes. For information pertinent to E-Government Act compliance related to this final rule, please contact Mr. Joseph Moxey, APHIS' Paperwork Reduction Act Coordinator, at (301) 851–2533.

Congressional Review Act

Pursuant to subtitle E of the Small Business Regulatory Enforcement Fairness Act of 1996 (also known as the Congressional Review Act, 5 U.S.C. 801 *et seq.*) OIRA has determined that this rule does not meet the criteria set forth in 5 U.S.C. 804(2).

Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104.4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, tribal governments, and the private sector. Under section 101 of the UMRA, APHIS generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures by State, local, or tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year. When such a statement is needed for a rule, section 205 of the UMRA generally requires APHIS to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, more cost-effective, or least burdensome alternative that achieves the objectives of the rule.

This rule contains no Federal mandates (under the regulatory provisions of title II of the UMRA) that may result in expenditures by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year. Thus, this rule is not subject to the requirements of sections 202 and 205 of the UMRA.

List of Subjects

9 CFR Part 71

Animal diseases, Livestock, Poultry and poultry products, Quarantine, Reporting and recordkeeping requirements, Transportation.

9 CFR Part 77

Animal diseases, Bison, Cattle, Reporting and recordkeeping requirements, Transportation, Tuberculosis.

9 CFR Part 78

Animal diseases, Bison, Cattle, Quarantine, Reporting and recordkeeping requirements, Swine, Transportation.

9 CFR Part 86

Animal diseases, Bison, Cattle, Livestock, Reporting and recordkeeping requirements.

For the reasons stated in the preamble, APHIS amends 9 CFR parts 71, 77, 78, and 86 as follows:

PART 71—GENERAL PROVISIONS

■ 1. The authority citation for part 71 continues to read as follows:

Authority: 7 U.S.C. 8301–8317; 7 CFR 2.22, 2.80, and 371.4.

■ 2. Amend § 71.1 by revising the definition of ''Official eartag'' to read as follows:

§ 71.1 Definitions.

* * * * *

Official eartag. An identification tag approved by APHIS that bears an official identification number for individual animals. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the

approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.

* * * * *

PART 77—TUBERCULOSIS

■ 3. The authority citation for part 77 continues to read as follows:

Authority: 7 U.S.C. 8301–8317; 7 CFR 2.22, 2.80, and 371.4.

■ 4. Amend § 77.2, by revising the definitions of ''Interstate certificate of veterinary inspection (ICVI)'' and ''Official eartag'' to read as follows:

§ 77.2 Definitions.

* * * * *

Interstate certificate of veterinary inspection (ICVI). An official document issued by a Federal, State, Tribal, or accredited veterinarian certifying the inspection of animals in preparation for interstate movement.

(1) The ICVI must show:

(i) The species of animals covered by the ICVI;

(ii) The number of animals covered by the ICVI;

(iii) The purpose for which the animals are to be moved;

(iv) The address at which the animals were loaded for interstate movement;

(v) The address to which the animals are destined; and

(vi) The names of the consignor and the consignee, and their addresses if different from the address at which the animals were loaded or the address to which the animals are destined.

(vii) Additionally, unless the species-specific requirements for ICVIs provide an exception, the ICVI must list the official identification number of each animal, except as provided in paragraph (2) of this definition, or group of animals moved that is required to be officially identified, or, if an alternative form of identification has been agreed upon by the sending and receiving States, the ICVI must include a record of that identification. If animals moving under a GIN also have individual official identification, only the GIN must be listed on the ICVI. An ICVI may not be issued for any animal that is not officially identified, if official identification is required. If the animals are not required by the regulations to be officially identified, the ICVI must state the exemption that applies (*e.g.,* the cattle and bison do not belong to one of the classes of cattle and bison to which the official identification requirements of this part apply). If the animals are required to be officially identified but the identification number does not have to be recorded on the ICVI, the ICVI must state that all animals to be moved under the ICVI are officially identified.

(2) As an alternative to recording individual animal identification on an ICVI, if agreed to by the receiving State or Tribe, another document may be attached to provide this information, but only under the following conditions:

(i) The document must be a State form or APHIS form that requires individual identification of animals, or a printout of official identification numbers generated by computer or other means;

(ii) A legible copy of the document must be attached to the original and each copy of the ICVI;

(iii) Each copy of the document must identify each animal to be moved with the ICVI. The document must not contain any information pertaining to other animals; and

(iv) The following information must be included in the identification column on the original and each copy of the ICVI:

(A) The name of the document; and

(B) Either the unique serial number on the document or both the name of the person who prepared the document and the date the document was signed.

* * * * *

Official eartag. An identification tag approved by APHIS that bears an official identification number for individual animals. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.

* * * * *

PART 78—BRUCELLOSIS

■ 5. The authority citation for part 78 continues to read as follows:

Authority: 7 U.S.C. 8301–8317; 7 CFR 2.22, 2.80, and 371.4.

■ 6. Amend § 78.1 by revising the definitions of ''Dairy cattle'', ''Interstate certificate of veterinary inspection (ICVI)'', and ''Official eartag'' to read as follows:

§ 78.1 Definitions.

* * * * *

Dairy cattle. All cattle, regardless of age or sex or current use, that are of a breed(s) or offspring of a breed used to produce milk or other dairy products for human consumption, including, but not limited to, Ayrshire, Brown Swiss, Holstein, Jersey, Guernsey, Milking Shorthorn, and Red and Whites.

* * * * *

Interstate certificate of veterinary inspection (ICVI). An official document issued by a Federal, State, Tribal, or accredited veterinarian certifying the inspection of animals in preparation for interstate movement.

(1) The ICVI must show:

(i) The species of animals covered by the ICVI;

(ii) The number of animals covered by the ICVI;

(iii) The purpose for which the animals are to be moved;

(iv) The address at which the animals were loaded for interstate movement;

(v) The address to which the animals are destined; and

(vi) The names of the consignor and the consignee and their addresses if different from the address at which the animals were loaded or the address to which the animals are destined.

(vii) Additionally, unless the species-specific requirements for ICVIs provide an exception, the ICVI must list the official identification number of each animal, except as provided in paragraph (2) of this definition, or group of animals moved that is required to be officially identified, or, if an alternative form of identification has been agreed upon by the sending and receiving States, the ICVI must include a record of that identification. If animals moving under a GIN also have individual official identification, only the GIN must be listed on the ICVI. An ICVI may not be issued for any animal that is not officially identified, if official identification is required. If the animals are not required by the regulations to be officially identified, the ICVI must state the exemption that applies (*e.g.,* the cattle and bison do not belong to one of the classes of cattle and bison to which the official identification requirements of this part apply). If the animals are required to be officially identified but the identification number does not have to be recorded on the ICVI, the ICVI must state that all animals to be moved under the ICVI are officially identified.

(2) As an alternative to recording individual animal identification on an ICVI, if agreed to by the receiving State or Tribe, another document may be attached to provide this information, but only under the following conditions:

(i) The document must be a Tribal or State form or APHIS form that requires individual identification of animals, or a printout of official identification numbers generated by computer or other means;

(ii) A legible copy of the document must be attached to the original and each copy of the ICVI;

(iii) Each copy of the document must identify each animal to be moved with the ICVI. The document must not

contain any information pertaining to other animals; and

(iv) The following information must be included in the identification column on the original and each copy of the ICVI:

(A) The name of the document; and

(B) Either the unique serial number on the document or both the name of the person who prepared the document and the date the document was signed.

* * * * *

Official eartag. An identification tag approved by APHIS that bears an official identification number for individual animals. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.

* * * * *

PART 86—ANIMAL DISEASE TRACEABILITY

■ 7. The authority citation for part 86 continues to read as follows:

Authority: 7 U.S.C. 8301–8317; 7 CFR 2.22, 2.80, and 371.4.

■ 8. Amend § 86.1 by:

■ a. Revising the definitions of ''Approved tagging site'', ''Dairy cattle'', and ''Interstate certificate of veterinary inspection (ICVI)'';

■ b. Adding in alphabetical order the definition for ''Official Animal Identification Device Standards (OAIDS)'';

■ c. Revising the definition of ''Official eartag''; and

■ d. Adding an OMB citation at the end of the section.

The revisions and additions read as follows:

§ 86.1 Definitions.

* * * * *

Approved tagging site. A premises, authorized by APHIS, State, or Tribal animal health officials, where livestock without official identification may be transferred to have official identification applied on behalf of their owner or the person in possession, care, or control of the animals when they are brought to the premises.

* * * * *

Dairy cattle. All cattle, regardless of age or sex or current use, that are of a breed(s) or offspring of a breed used to produce milk or other dairy products for human consumption, including, but not limited to, Ayrshire, Brown Swiss, Holstein, Jersey, Guernsey, Milking Shorthorn, and Red and Whites.

* * * * *

Interstate certificate of veterinary inspection (ICVI). An official document issued by a Federal, State, or Tribal government, or an accredited veterinarian, certifying the inspection of animals in preparation for interstate movement.

(1) The ICVI must show:

(i) The species of animals covered by the ICVI;

(ii) The number of animals covered by the ICVI;

(iii) The purpose for which the animals are to be moved;

(iv) The address at which the animals were loaded for interstate movement;

(v) The address to which the animals are destined; and

(vi) The names of the consignor and the consignee and their addresses if different from the address at which the animals were loaded or the address to which the animals are destined.

(vii) Additionally, unless the species-specific requirements for ICVIs provide an exception, the ICVI must list the official identification number of each animal, except as provided in paragraph (2) of this definition, or group of animals moved that is required to be officially identified, or, if an alternative form of identification has been agreed upon by the sending and receiving States, the ICVI must include a record of that identification. If animals moving under a GIN also have individual official identification, only the GIN must be listed on the ICVI. An ICVI may not be issued for any animal that is not officially identified if official identification is required. If the animals are not required by the regulations to be officially identified, the ICVI must state the exemption that applies (*e.g.,* the cattle and bison do not belong to one of the classes of cattle and bison to which the official identification requirements of this part apply). If the animals are required to be officially identified but the identification number does not have to be recorded on the ICVI, the ICVI must state that all animals to be moved under the ICVI are officially identified.

(2) As an alternative to recording individual animal identification on an ICVI, if agreed to by the receiving State or Tribe, another document may be attached to provide this information, but only under the following conditions:

(i) The document must be a State form or APHIS form that requires individual identification of animals, or a printout of official identification numbers generated by computer or other means;

(ii) A legible copy of the document must be attached to the original and each copy of the ICVI;

(iii) Each copy of the document must identify each animal to be moved with the ICVI. The document must not contain any information pertaining to other animals; and

(iv) The following information must be included in the identification column on the original and each copy of the ICVI:

(A) The name of the document; and

(B) Either the unique serial number on the document or both the name of the person who prepared the document and the date the document was signed.

* * * * *

Official Animal Identification Device Standards (OAIDS). A document providing further information regarding the official identification device recordkeeping requirements of this part, and technical descriptions, specifications, and details under which APHIS would approve identification devices for official use. Updates or modifications to the Standards document will be announced to the public by means of a notice published in the **Federal Register**.

Official eartag. An identification tag approved by APHIS that bears an official identification number for individual animals. The design, size, shape, color, and other characteristics of the official eartag will depend on the needs of the users, subject to the approval of the Administrator. The official eartag must be tamper-resistant and have a high retention rate in the animal.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0327)

■ 9. Revise § 86.2 to add an OMB citation at the end of the section to read as follows:

§ 86.2 General requirements for traceability.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0327)

■ 10. Revise § 86.3 to read as follows:

§ 86.3 Recordkeeping requirements.

(a) Any State, Tribe, accredited veterinarian, or other person or entity who distributes official identification devices must maintain for 5 years a record of the names and addresses of anyone to whom the devices were distributed. Official identification device distribution records must be entered by the person distributing the devices into the Tribal, State, Federal, or other database acceptable to each government entity. Additional guidance on meeting these recordkeeping requirements is found in the OAIDS.

(b) Records of official identification devices applied by a federally

accredited veterinarian to a client animal must be kept in a readily accessible record system.

(c) Approved livestock facilities must keep any ICVIs or alternate documentation that is required by this part for the interstate movement of covered livestock that enter the facility on or after March 11, 2013. For poultry and swine, such documents must be kept for at least 2 years, and for cattle and bison, sheep and goats, cervids, and equids, 5 years.

(d) Records required under paragraphs (a) through (c) of this section must be maintained by the responsible person or entity and must be of sufficient accuracy, quality, and completeness to demonstrate compliance with all conditions and requirements under this part. During normal business hours, APHIS must be allowed access to all records, to include visual inspection and reproduction (*e.g.,* photocopying, digital reproduction). The responsible person or entity must submit to APHIS all reports and notices containing the information specified within 48 hours of receipt of request, or earlier if warranted by an emergency disease response.

(Approved by the Office of Management and Budget under control number 0579–0327)

■ 11. Amend § 86.4 by:
■ a. Revising paragraphs (a) introductory text and (a)(1)(i);
■ b. In paragraphs (a)(2)(i) and (iv), removing the word ''equine'' and adding in its place the word ''equid'' wherever it appears;
■ c. In paragraph (a)(2)(iii), removing the words ''to the equine'' and adding in their place the words ''into the equid'';
■ d. In paragraph (a)(2)(v), removing the word ''equines'' and adding in its place the word ''equids'';
■ e. Adding paragraph (b)(1)(ii)(D);
■ f. Revising paragraphs (b)(1)(iii)(B), (b)(4) introductory text, and (c)(3);
■ g. Removing paragraph (c)(4);
■ h. Revising paragraphs (e)(1)(iii) and (iv);
■ i. Adding in paragraph (e)(2)(iv) the words ''or other EID'' between the words ''RFID'' and ''eartag''; and
■ j. Adding an OMB citation at the end of the section.

The additions and revisions read as follows:

§ 86.4 Official identification.

(a) *Official identification devices and methods.* The Administrator has approved the following official identification devices or methods for the species listed. The Administrator may authorize the use of additional devices or methods for a specific species if he or she determines that such additional devices or methods will provide for adequate traceability. Additional guidance on official identification devices, methods, and the approval process is found in the Official Animal Identification Device Standards (OAIDS) document.

(1) * * *

(i) For an official eartag, beginning November 5, 2024, all official eartags sold for or applied to cattle and bison must be readable both visually and electronically (EID);

* * * * *

(b) * * *

(1) * * *

(ii) * * *

(D) Cattle and bison leaving a slaughter establishment may only be moved to another recognized slaughter establishment or approved feedlot and can only be sold/re-sold as slaughter cattle, and they must be accompanied by an owner-shipper statement in accordance with § 86.5(c)(1). Information listed on the document must include the name and address of the slaughter establishment from which the animals left, the official identification numbers, as defined in § 86.1, correlated with the USDA backtag number (if available), the name of the destination slaughter establishment, or approved feedlot (as defined in § 77.5 of this subchapter) to which the animals are being shipped.

(iii) * * *

(B) All dairy cattle;

* * * * *

(4) *Horses and other equids.* Horses and other equids moving interstate must be officially identified prior to the interstate movement, using an official identification device or method listed in paragraph (a)(2) of this section unless:

* * * * *

(c) * * *

(3) A visually and electronically readable eartag may be applied to an animal that is already officially identified with one or more non-EID official eartags and/or a non-EID official vaccination eartag used for brucellosis. The person applying the new visually and electronically readable eartag must record the date the eartag is applied to the animal and the official identification numbers of both official eartags and must maintain those records for 5 years.

* * * * *

(e) * * *

(1) * * *

(iii) Malfunction of the electronic component of an electronically readable (EID) device; or

(iv) Incompatibility or inoperability of the electronic component of an EID device with the management system or unacceptable functionality of the management system due to use of an EID device.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0327)

■ 12. Revise § 86.5 to read as follows:

§ 86.5 Documentation requirements for interstate movement of covered livestock.

(a) *Responsible persons and required documentation.* The persons responsible for animals leaving a premises for interstate movement must ensure that the animals are accompanied by an interstate certificate of veterinary inspection (ICVI) or other document required by this part for the interstate movement of animals.

(b) *Forwarding of documents.* (1) The APHIS representative, State or Tribal representative, or accredited veterinarian issuing an ICVI or other document required for the interstate movement of animals under this part, must forward a copy of the ICVI or other document to the State or Tribal animal health official of the State or Tribe of origin within 7 calendar days from the date on which the ICVI or other document is issued. The State or Tribal animal health official in the State or Tribe of origin must forward a copy of the ICVI or other document to the State or Tribal animal health official in the State or Tribe of destination within 7 calendar days from date on which the ICVI or other document is received.

(2) The animal health official or accredited veterinarian issuing or receiving an ICVI or other interstate movement document in accordance with paragraph (b)(1) of this section must keep a copy of the ICVI or alternate documentation. For poultry and swine, such documents must be kept for at least 2 years, and for cattle and bison, sheep and goats, cervids, and equine species, 5 years.

(c) *Cattle and bison.* Cattle and bison moved interstate must be accompanied by an ICVI unless:

(1) They are moved directly to a recognized slaughtering establishment, or directly to an approved livestock facility and then directly to a recognized slaughtering establishment, and they are accompanied by an owner-shipper statement.

(2) They are moved directly to an approved livestock facility with an owner-shipper statement and do not move interstate from the facility unless accompanied by an ICVI.

(3) They are moved from the farm of origin for veterinary medical examination or treatment and returned

to the farm of origin without change in ownership.

(4) They are moved directly from one State through another State and back to the original State.

(5) They are moved as a commuter herd with a copy of the commuter herd agreement or other document, as agreed to by the States or Tribes involved in the movement.

(6) Additionally, cattle and bison may be moved between shipping and receiving States or Tribes with documentation other than an ICVI, *e.g.,* a brand inspection certificate, as agreed upon by animal health officials in the shipping and receiving States or Tribes.

(7) The official identification number of cattle or bison must be recorded on the ICVI or alternate documentation unless:

(i) The cattle or bison are moved from an approved livestock facility directly to a recognized slaughtering establishment; or

(ii) The cattle and bison are sexually intact cattle or bison under 18 months of age or steers or spayed heifers; except that this paragraph (c)(7)(ii) does not apply to dairy cattle of any age or to cattle or bison used for rodeo, exhibition, or recreational purposes.

(d) *Horses and other equine species.* Horses and other equine species moved interstate must be accompanied by an ICVI unless:

(1) They are used as the mode of transportation (horseback, horse and buggy) for travel to another location and then return direct to the original location; or

(2) They are moved from the farm or stable for veterinary medical examination or treatment and returned to the same location without change in ownership; or

(3) They are moved directly from a location in one State through another State to a second location in the original State.

(4) Additionally, equids may be moved between shipping and receiving States or Tribes with documentation other than an ICVI, *e.g.,* an equine infectious anemia test chart, as agreed to by the shipping and receiving States or Tribes involved in the movement.

(5) Equids moving commercially to slaughter must be accompanied by documentation in accordance with part 88 of this subchapter. Equine infectious anemia reactors moving interstate must be accompanied by documentation as required by part 75 of this subchapter.

(e) *Poultry.* Poultry moved interstate must be accompanied by an ICVI unless:

(1) They are from a flock participating in the National Poultry Improvement Plan (NPIP) and are accompanied by the documentation required under the NPIP regulations (parts 145 through 147 of this chapter) for participation in that program; or

(2) They are moved directly to a recognized slaughtering or rendering establishment; or

(3) They are moved from the farm of origin for veterinary medical examination, treatment, or diagnostic purposes and either returned to the farm of origin without change in ownership or euthanized and disposed of at the veterinary facility; or

(4) They are moved directly from one State through another State and back to the original State; or

(5) They are moved between shipping and receiving States or Tribes with a VS Form 9–3 or documentation other than an ICVI, as agreed upon by animal health officials in the shipping and receiving States or Tribes; or

(6) They are moved under permit in accordance with part 82 of this subchapter.

(f) *Sheep and goats.* Sheep and goats moved interstate must be accompanied by documentation as required by part 79 of this subchapter.

(g) *Swine.* Swine moved interstate must be accompanied by documentation in accordance with § 71.19 of this subchapter or, if applicable, with part 85 of this subchapter.

(h) *Captive cervids.* Captive cervids moved interstate must be accompanied by documentation as required by part 77 of this subchapter.

(Approved by the Office of Management and Budget under control number 0579–0327)

Done in Washington, DC, this 26th day of April 2024.

Jennifer Moffitt,

Under Secretary for Marketing and Regulatory Programs.

[FR Doc. 2024–09717 Filed 5–8–24; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 25

[Docket No. FAA–2024–0566; Special Conditions No. 25–861–SC]

Special Conditions: The Boeing Model 737–8 Airplane; Dynamic Test Requirements for Single-Occupant Oblique Seats With 3-Point Seat Belt With Pretensioner

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final special conditions; request for comments.

SUMMARY: These special conditions are issued for The Boeing Company (Boeing) Model 737–8 series airplane. This airplane, as modified by HAECO Cabin Solutions, LLC. (HAECO), will have a novel or unusual design feature when compared to the state of technology envisioned in the airworthiness standards for transport-category airplanes. This design feature is single-occupant oblique (side-facing) seats equipped with a 3-point seat belt with pretensioner. The applicable airworthiness regulations do not contain adequate or appropriate safety standards for this design feature. These special conditions contain the additional safety standards that the Administrator considers necessary to establish a level of safety equivalent to that established by the existing airworthiness standards.

DATES: This action is effective on HAECO on May 9, 2024. Send comments on or before June 24, 2024.

ADDRESSES: Send comments identified by Docket No. FAA–2024–0566 using any of the following methods:

- *Federal eRegulations Portal:* Go to *www.regulations.gov* and follow the online instructions for sending your comments electronically.
- *Mail:* Send comments to Docket Operations, M–30, U.S. Department of Transportation, 1200 New Jersey Avenue SE, Room W12–140, West Building Ground Floor, Washington, DC 20590–0001.
- *Hand Delivery or Courier:* Take comments to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE, Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.
- *Fax:* Fax comments to Docket Operations at 202–493–2251.

Docket: Background documents or comments received may be read at *www.regulations.gov* at any time. Follow the online instructions for accessing the docket or go to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE, Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: John Shelden, Cabin Safety Section, AIR–624, Technical Policy Branch, Policy and Standards Division, Aircraft Certification Service, Federal Aviation Administration, 2200 South 216th Street, Des Moines, Washington 98198; telephone and fax (206) 231–3214; email *john.shelden@faa.gov.*

SUPPLEMENTARY INFORMATION: The substance of these special conditions has been published in the **Federal**

Register for public comment in several prior instances with no substantive comments received. Therefore, the FAA finds, pursuant to 14 CFR 11.38(b), that new comments are unlikely, and notice and comment prior to this publication are unnecessary.

Privacy

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in title 14, Code of Federal Regulations (14 CFR) 11.35, the FAA will post all comments received without change to *www.regulations.gov,* including any personal information you provide. The FAA will also post a report summarizing each substantive verbal contact received about these special conditions.

Confidential Business Information

Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (FOIA) (5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to this notice contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this notice, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ''PROPIN.'' The FAA will treat such marked submissions as confidential under the FOIA, and the indicated comments will not be placed in the public docket of these proposed special conditions. Send submissions containing CBI to the individual listed in the For Further Information Contact section below. Comments the FAA receives, which are not specifically designated as CBI, will be placed in the public docket for these proposed special conditions.

Comments Invited

The FAA invites interested people to take part in this rulemaking by sending written comments, data, or views. The most helpful comments reference a specific portion of the special conditions, explain the reason for any recommended change, and include supporting data.

The FAA will consider all comments received by the closing date for comments. The FAA may change these special conditions based on the comments received.

Background

On December 20, 2022, HAECO applied for a supplemental type certificate for the installation of oblique (side-facing) passenger seats that incorporate a 3-point restraint with pretensioner system in Boeing Model 737–8 series airplanes. The Boeing Model 737–8 series airplane is a twin-engine, transport category airplane with a maximum passenger capacity of 189, and a maximum takeoff weight of approximately 182,200 pounds.

Type Certification Basis

Under the provisions of title 14, Code of Federal Regulations (14 CFR) 21.101, HAECO must show that the Model 737–8 series airplane, as changed, continue to meet the applicable provisions of the regulations listed in Type Certificate No. A16WE, or the applicable regulations in effect on the date of application for the change, except for earlier amendments as agreed upon by the FAA.

If the Administrator finds that the applicable airworthiness regulations (*e.g.,* 14 CFR part 25) do not contain adequate or appropriate safety standards for the Boeing Model 737–8 series airplane because of a novel or unusual design feature, special conditions are prescribed under the provisions of § 21.16.

Special conditions are initially applicable to the model for which they are issued. Should the type certificate for that model be amended later to include any other model that incorporates the same novel or unusual design feature, or should any other model already included on the same type certificate be modified to incorporate the same novel or unusual design feature, the special conditions would also apply to the other model under § 21.101.

In addition to the applicable airworthiness regulations and special conditions, the Boeing Model 737–8 series airplane must comply with the exhaust-emission requirements of 14 CFR part 34, and the noise-certification requirements of 14 CFR part 36.

The FAA issues special conditions, as defined in 14 CFR 11.19, in accordance with § 11.38, and they become part of the type certification basis under § 21.101.

Novel or Unusual Design Features

The Boeing Model 737–8 series airplane, as modified by HAECO, will incorporate a novel or unusual design feature which is the installation of oblique (side-facing) passenger seats, which may include a 3-point restraint system with pretensioner. These oblique seats may be installed at an angle of 18 to 45 degrees to the aircraft centerline and have surrounding furniture that introduces occupant alignment and loading concerns.

Discussion

Title 14, Code of Federal Regulations (14 CFR) 25.785(d) requires that each occupant of a seat that makes more than an 18 degree angle with the vertical plane containing the airplane centerline must be protected from head injury by a safety belt and an energy absorbing rest that will support the arms, shoulders, head, and spine, or by a safety belt and shoulder harness that will prevent the head from contacting any injurious object.

The proposed Boeing Model 737–8 airplane seat installation is novel in that the current requirements do not adequately address protection of the occupant's neck and spine for seating configurations that are positioned at angles greater than 18 degrees up to and including 45 degrees from the airplane centerline. The installation of passenger seats at angles of 18 to 45 degrees to the airplane centerline is unique due to the seat/occupant interface with the surrounding furniture that introduces occupant alignment/loading concerns with or without the installation of a 3-point restraint system.

In order to provide a level of safety that is equivalent to that afforded to occupants of forward and aft facing seating, additional airworthiness standards, in the form of new special conditions, are necessary.

The FAA has been conducting and sponsoring research on appropriate injury criteria for oblique (side-facing) seat installations. To reflect current research findings, the FAA issued Policy Statement PS–AIR–25–27, ''Technical Criteria for Approving Side-Facing Seats,'' dated July 11, 2018, which defines injury criteria for oblique seats.

FAA-sponsored research has found that an un-restrained flailing of the upper torso, even when the pelvis and torso are nearly aligned, can produce serious spinal and torso injuries. At lower impact severities, even with significant misalignment between the torso and pelvis, these injuries did not occur. Tests with an FAA H–III anthropomorphic test dummy (ATD) have identified a level of lumbar spinal tension corresponding to the no-injury impact severity. This level of tension is included as a limit in the special conditions. The spine tension limit selected is conservative with respect to other aviation injury criteria since it

corresponds to a no-injury loading condition.

Other restraint systems have been used to comply with the occupant injury criteria of § 25.562(c)(5). For instance, shoulder harnesses have been widely used on flight-attendant seats, flight-deck seats, in business jets, and in general-aviation airplanes to reduce occupant head injury in the event of an emergency landing. Special conditions, pertinent regulations, and published guidance relate to other restraint systems. However, the use of pretensioners in the restraint system on transport-airplane seats is a novel design.

Pretensioner technology involves a step-change in loading experienced by the occupant for impacts below and above that at which the device deploys, because activation of the shoulder harness, at the point at which the pretensioner engages, interrupts upper-torso excursion. Such excursion could result in the head-injury criteria (HIC) being higher at an intermediate impact condition than that resulting from the maximum impact condition corresponding to the test conditions specified in § 25.562. See condition 7 in these special conditions.

The ideal triangular maximum-severity pulse is defined in Advisory Circular (AC) 25.562–1B, ''Dynamic Evaluation of Seat Restraint Systems and Occupant Protection on Transport Airplanes''. For the evaluation and testing of less-severe pulses for purposes of assessing the effectiveness of the pretensioner setting, a similar triangular pulse should be used with acceleration, rise time, and velocity change scaled accordingly. The magnitude of the required pulse should not deviate below the ideal pulse by more than 0.5g until 1.33 t1 is reached, where t1 represents the time interval between 0 and t1 on the referenced pulse shape, as shown in AC 25.562–1B. This is an acceptable method of compliance to the test requirements of the special conditions.

Additionally, the pretensioner might not provide protection, after actuation, during secondary impacts. Therefore, the case where a small impact is followed by a large impact should be addressed. If the minimum deceleration severity at which the pretensioner is set to deploy is unnecessarily low, the protection offered by the pretensioner may be lost by the time a second, larger impact occurs.

The existing special conditions for Boeing Model 737–8 series airplane oblique seat installations do not address oblique seats with 3-point restraint systems equipped with pretensioners. Therefore, the proposed configuration requires special conditions.

Conditions 1 through 7 address occupant protection in consideration of the oblique-facing seats. Conditions 8 through 10 ensure that the pretensioner system activates when intended and protects a range of occupants under various accident conditions. Conditions 11 through 16 address maintenance and reliability of the pretensioner system, including any outside influences on the mechanism, to ensure it functions as intended.

These special conditions contain the additional safety standards that the Administrator considers necessary to establish a level of safety equivalent to that established by the existing airworthiness standards.

Applicability

As discussed above, these special conditions are applicable to the Boeing Model 737–8 series airplane, modified by HAECO. Should HAECO apply at a later date for a supplemental type certificate to modify any other model included on Type Certificate No. A16WE to incorporate the same novel or unusual design feature, these special conditions would apply to that model as well.

Conclusion

This action affects only a certain novel or unusual design feature on one model series of airplanes. It is not a rule of general applicability and affects only the applicant who applied to the FAA for approval of these features on the airplane.

List of Subjects in 14 CFR Part 25

Aircraft, Aviation safety, Reporting and recordkeeping requirements.

Authority Citation

The authority citation for these special conditions is as follows:

Authority: 49 U.S.C. 106(f), 106(g), 40113, 44701, 44702, and 44704.

The Special Conditions

Accordingly, pursuant to the authority delegated to me by the Administrator, the following special conditions are issued as part of the type certification basis for The Boeing Company Model 737–8 series airplanes, modified by HAECO.

In addition to the requirements of § 25.562, passenger seats installed at an angle between 18 degrees and 45 degrees from the aircraft centerline must meet the following conditions:

1. Body-to-Wall/Furnishing Contact

If a seat is installed aft of a structure (*e.g.,* interior wall or furnishings) that does not provide a homogenous contact surface for the expected range of occupants and yaw angles, then additional analysis and tests may be required to demonstrate that the injury criteria are met for the area that an occupant could contact. For example, if, in addition to a pretensioner restraint system, an airbag device is present, different yaw angles could result in different airbag device performance, then additional analysis or separate tests may be necessary to evaluate performance.

2. Neck Injury Criteria

The seating system must protect the occupant from experiencing serious neck injury. In addition to a pretensioner restraint system, if an airbag device also is present, the assessment of neck injury must be conducted with the airbag device activated, unless there is reason to also consider that the neck injury potential would be higher for impacts below the airbag-device deployment threshold.

(a) The Nij (calculated in accordance with 49 CFR 571.208) must be below 1.0, where

Nij = Fz/Fzc + My/Myc, and Nij critical values are:

(1) Fzc = 1530 lbs. for tension
(2) Fzc = 1385 lbs. for compression
(3) Myc = 229 lb-ft in flexion
(4) Myc = 100 lb-ft in extension

(b) In addition, peak Fz must be below 937 lbs. in tension and 899 lbs. in compression.

(c) Rotation of the head about its vertical axis relative to the torso is limited to 105 degrees in either direction from forward facing.

(d) The neck must not impact any surface that would produce concentrated loading on the neck.

3. Spine and Torso Injury Criteria

(a) The lumbar spine tension (Fz) cannot exceed 1200 lbs.

(b) Significant concentrated loading on the occupant's spine, in the area between the pelvis and shoulders during impact, including rebound, is not acceptable. During this type of contact, the interval for any rearward (X direction) acceleration exceeding 20g must be less than 3 milliseconds as measured by the thoracic instrumentation specified in 49 CFR part 572, subpart E filtered in accordance with SAE International (SAE) recommended practice J211/1, ''Instrumentation for Impact Test—Part 1—Electronic Instrumentation.''

(c) The occupant must not interact with the armrest or other seat components in any manner significantly different than would be expected for a forward-facing seat installation.

4. Pelvis Criteria

Any part of the load-bearing portion of the bottom of the ATD pelvis must not translate beyond the edges of the seat bottom seat-cushion supporting structure.

5. Femur Criteria

Axial rotation of the upper leg (about the z-axis of the femur per SAE Recommended Practice J211/1) must be limited to 35 degrees from the nominal seated position. Evaluation during rebound does not need to be considered.

6. ATD and Test Conditions

Longitudinal tests conducted to measure the injury criteria above must be performed with the FAA Hybrid III ATD, as described in SAE 1999–01–1609, ''A Lumbar Spine Modification to the Hybrid III ATD for Aircraft Seat Tests.'' The tests must be conducted with an undeformed floor, at the most-critical yaw cases for injury, and with all lateral structural supports (*e.g.,* armrests or walls) installed.

Note: HAECO must demonstrate that the installation of seats via plinths or pallets meets all applicable requirements. Compliance with the guidance contained in Policy Memorandum PS–ANM–100–2000–00123, ''Guidance for Demonstrating Compliance with Seat Dynamic Testing for Plinths and Pallets,'' dated February 2, 2000, is acceptable to the FAA.

7. Head Injury Criteria (HIC)

The HIC value must not exceed 1000 at any condition at which the pretensioner does or does not deploy, up to the maximum severity pulse that corresponds to the test conditions specified in § 25.562. Tests must be performed to demonstrate this, taking into account any necessary tolerances for deployment.

8. Protection During Secondary Impacts

The pretensioner activation setting must be demonstrated to maximize the probability of the protection being available when needed, considering secondary impacts.

9. Protection of Occupants Other Than 50th Percentile

Protection of occupants for a range of stature from a 2-year-old child to a 95th percentile male must be shown. For shoulder harnesses that include pretensioners, protection of occupants other than a 50th percentile male may be shown by test or analysis. In addition, the pretensioner must not introduce a hazard to passengers due to the following seat configurations:

(a) The seat occupant is holding an infant.

(b) The seat occupant is a child in a child-restraint device.

(c) The seat occupant is a pregnant woman.

10. Occupants Adopting the Brace Position

Occupants in the traditional brace position when the pretensioner activates must not experience adverse effects from the pretensioner activation.

11. Inadvertent Pretensioner Actuation

(a) The probability of inadvertent pretensioner actuation must be shown to be extremely remote (*i.e.,* average probability per flight hour of less than 10^{-7}).

(b) The system must be shown not susceptible to inadvertent pretensioner actuation because of wear and tear, or inertia loads resulting from in-flight or ground maneuvers likely to be experienced in service.

(c) The seated occupant must not be seriously injured because of inadvertent pretensioner actuation.

(d) Inadvertent pretensioner activation must not cause a hazard to the airplane, nor cause serious injury to anyone who may be positioned close to the retractor or belt (*e.g.,* seated in an adjacent seat or standing adjacent to the seat).

12. Availability of the Pretensioner Function Prior to Flight

The design must provide means for a crewmember to verify the availability of the pretensioner function prior to each flight, or the probability of failure of the pretensioner function must be demonstrated to be extremely remote (*i.e.,* average probability per flight hour of less than 10^{-7}), between inspection intervals.

13. Incorrect Seat Belt Orientation

The system design must ensure that any incorrect orientation (twisting) of the seat belt does not compromise the pretensioner protection function.

14. Contamination Protection

The pretensioner mechanisms and controls must be protected from external contamination associated with that which could occur on or around passenger seating.

15. Prevention of Hazards

The pretensioner system must not induce a hazard to passengers in case of fire, nor create a fire hazard, if activated.

16. Functionality After Loss of Power

The system must function properly after loss of normal airplane electrical power, and after a transverse separation in the fuselage at the most critical location. A separation at the location of the system does not have to be considered.

Issued in Kansas City, Missouri, on May 3, 2024.

Patrick R. Mullen,

Manager, Technical Policy Branch, Policy and Standards Division, Aircraft Certification Service.

[FR Doc. 2024–10075 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–13–P

FEDERAL MARITIME COMMISSION

46 CFR Part 541

[Docket No. FMC–2022–0066]

RIN 3072–AC90

Demurrage and Detention Billing Requirements; Correction

AGENCY: Federal Maritime Commission.

ACTION: Final rule; correction.

SUMMARY: This document corrects the preamble to a final rule published in the **Federal Register** on February 26, 2024, concerning demurrage and detention billing requirements. This correction provides information regarding situations in which vessel-operating common carriers (VOCCs) enter into written contracts with motor carriers that use containers in the transportation of goods.

DATES: This action is effective on May 9, 2024.

ADDRESSES: To view background documents or comments received, you may use the Federal eRulemaking Portal at *www.regulations.gov* under Docket No. FMC–2022–0066.

FOR FURTHER INFORMATION CONTACT: David Eng, Secretary; Phone: (202) 523–5725; Email: *secretary@fmc.gov.*

SUPPLEMENTARY INFORMATION: The Commission notes that it has received several inquiries concerning a possible discrepancy between the rule text and one paragraph in the preamble, found at page 14336.[1] The Commission

[1] ''In regard to the second comment, there seems to be a misunderstanding on the commenter's part about the rule's applicability. As discussed in the NPRM, a primary purpose of this rule is to stop demurrage and detention invoices from being sent to parties who did not negotiate contract terms with the billing party. That concern is not present where a motor carrier has directly contracted with a VOCC. Nothing in this rule, either in the proposed

Continued

appreciates these inquiries as they reflect the strong interest within the shipping industry in ensuring compliance with applicable regulations. These inquiries have helped this clarification issue well before the rule goes into effect on May 28, 2024.

In the preamble, the Commission responded to a comment requesting that we amend the definition of ''billed party'' to address situations in which vessel-operating common carriers (VOCCs) enter into written contracts with motor carriers that use containers in the transportation of goods. The Commission responded by declining to adopt this proposed change, and we now reiterate that conclusion—demurrage and detention should be billed to either the person for whose account the billing party provided ocean transportation or storage of cargo and who contracted with the billing party for the ocean transportation or storage of cargo, or the consignee.

The Commission's explanation in the preamble was intended to further explain that the rule only addresses carrier-trucker relationships on through bills of lading. The Commission meant this to be understood in the context of its statement that ''the FMC's jurisdiction, and thus this rule, would apply only to cargo moved inland under a through bill of lading and contracts between a VOCC [and] a motor carrier not based on a through bill of lading would likely be outside the scope of this rule.'' We further did not intend the paragraph to suggest that there is an exception to the rule's clear direction regarding who may be a ''billed party''. However, we now see that the inadvertent inclusion of certain language renders this comment response ambiguous, and we take this opportunity to clarify our intention by correcting the language in the preamble.

Accordingly, in FR Doc. 2024–02926, on page 14336, in the third column, the paragraph beginning with ''In regard to . . .'' is corrected to read as follows:

''In regard to the second comment, the rule makes clear that demurrage and detention invoices can only be issued to either the person for whose account the billing party provided ocean transportation or storage of cargo and who contracted with the billing party for the ocean transportation or storage of cargo, or the consignee. As discussed in the NPRM, a primary purpose of this rule is to stop demurrage and detention invoices from being sent to parties who did not negotiate contract terms for ocean transportation or storage of cargo with the billing party. When a VOCC issues a detention or demurrage invoice, the VOCC must comply with the requirements of part 541. However, in our response to this specific comment, we presume that the FMC's jurisdiction would apply only to cargo moved inland under a through bill of lading, and that contracts between a VOCC and a motor carrier not based on a through bill of lading would likely be outside the scope of this rule.''

By the Commission.

Dated: May 3, 2024.

David Eng,

Secretary.

[FR Doc. 2024–10136 Filed 5–8–24; 8:45 am]

BILLING CODE 6730–02–P

or final version, prohibits a VOCC from issuing a demurrage or detention invoice to a motor carrier when a contractual relationship exists between the VOCC and the motor carrier for the motor carrier to provide carriage or storage of goods to the VOCC. The definition of ''billed party'' is intentionally broad to capture any party to whom a detention or demurrage invoice is issued. When a VOCC issues a detention or demurrage invoice to a motor carrier, the VOCC must comply with the requirements of part 541. The Commission has jurisdiction over common carriers, marine terminal operators (MTOs), and ocean transportation intermediaries (OTIs), including over through transportation. Without knowing the particulars of the hypothetical, in this situation, presumably the FMC's jurisdiction, and thus this rule, would apply only to cargo moved inland under a through bill of lading and contracts between a VOCC. A motor carrier not based on a through bill of lading would likely be outside the scope of this rule.''

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 171, 172, 173, 175, 176, 178, and 180

[Docket No. PHMSA–2021–0092 (HM–215Q)]

RIN 2137–AF57

Hazardous Materials: Harmonization With International Standards; Correction

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule; correction.

SUMMARY: The Pipeline and Hazardous Materials Safety Administration is correcting a final rule that was published in the **Federal Register** on April 10, 2024. The final rule was published to maintain alignment with international regulations and standards by adopting various amendments, including changes to proper shipping names, hazard classes, packing groups, special provisions, packaging authorizations, air transport quantity limitations, and vessel stowage requirements. The corrections address several errors to the hazardous material entries in the hazardous materials table.

DATES: This correction is effective May 10, 2024.

FOR FURTHER INFORMATION CONTACT: Steven Andrews, Standards and Rulemaking, or Candace Casey, Standards and Rulemaking, at 202–366–8553, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, 1200 New Jersey Avenue SE, East Building, 2nd Floor, Washington, DC 20590–0001.

SUPPLEMENTARY INFORMATION:

I. Background and Need for Technical Corrections

On April 10, 2024, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published a final rule in the **Federal Register** entitled ''Hazardous Materials: Harmonization with International Standards.'' [1] In the final rule, the amendatory instruction 19c for the revision of Table 4 to paragraph (g) in § 173.225 should have read: ''In newly designated Table 4 to paragraph (g), under UN No. 3109, and above ''tert-Butyl hydroperoxide, not more than 72% with water'' add an entry for ''tert-Butyl hydroperoxide, not more than 56% with diluent type B[2]'' and revise the Notes after newly designated table 4 to paragraph (g) to read as follows.'' The publication of this correction is needed to ensure that the final rule's amendment of Table 4 to paragraph (g) of § 173.225—which the amendment is effective May 10, 2024—will read as intended.

Additionally, changes in the final rule included numerous amendments to the § 172.101 Hazardous Materials Table (HMT). Unfortunately, the amendments to a few of the table entries introduced new unintended errors that PHMSA is correcting in this notice. The unintended errors are summarized below.

• *UN3548, Articles containing miscellaneous dangerous goods, n.o.s.:* In HM–215Q, PHMSA revised the entry ''UN3548, Articles containing miscellaneous dangerous goods, n.o.s.'' to add Special Provision A224 to Column 7. Special Provision A224 allows for the transport of large articles containing a non-flammable, non-toxic gas or environmentally hazardous substances on both passenger aircraft and cargo aircraft only under certain conditions. As a part of this HM–215Q revision, PHMSA inadvertently removed label code ''9'' from Column 6. Label Code ''9'' in Column 6 is necessary to ensure Class 9 labels are placed on packages shipped under

[1] 89 FR 25434 (Apr. 10, 2024).

''UN3548, Articles containing miscellaneous dangerous goods, n.o.s.'' To meet the original intent of HM–215Q to harmonize with international standards, PHMSA is correcting this error in this notice. *See* ''Section III. Corrections.''

• *UN3538, Articles containing non-flammable, non-toxic gas, n.o.s.:* In HM–215Q, PHMSA revised the entry ''UN3538, Articles containing non-flammable, non-toxic gas, n.o.s.,'' to add Special Provision A225 to Column 7. Special Provision A225 allows for the transport of large articles containing a non-flammable, non-toxic gas or environmentally hazardous substances on both passenger aircraft and cargo aircraft only under certain conditions. As a part of this revision, PHMSA inadvertently removed the ''G'' from Column 1 of the ''UN3538, Articles containing non-flammable, non-toxic gas, n.o.s.'' entry. The ''G'' in Column 1 identifies proper shipping names for which one or more technical names of the hazardous material must be entered in parentheses, in association with the basic description. To meet the original intent of HM–215Q to harmonize with international standards, PHMSA is correcting this error in this notice. *See* ''Section III. Corrections.''

• *UN2922, Corrosive liquids, toxic, n.o.s.:* In HM–215Q, PHMSA made a revision to the entry ''UN2922, Corrosive liquid, toxic, n.o.s.'' to add Special Provision A4 to Column 7. Special Provision A4 addresses liquids and solids in PG I that also pose an inhalation toxicity hazard by limiting or prohibiting their transportation on aircraft. As written, the regulatory instructions in HM–215Q might inadvertently remove the PG II and III entries for ''UN2922, Corrosive liquid, toxic, n.o.s.'' Therefore, the regulatory instruction needs to be revised to ensure that PG II and III for ''UN2922, Corrosive liquid, toxic, n.o.s.'' are not deleted from the HMT. To meet the original intent of HM–215Q to harmonize with international standards, PHMSA is correcting this error in this notice. *See* ''Section III. Corrections.''

• *UN2923, Corrosive solids, toxic, n.o.s.:* In HM–215Q, PHMSA made a revision to the entry ''UN2923, Corrosive solids, toxic, n.o.s.'' to add Special Provision A5 to Column 7. Special Provision A5 addresses liquids and solids in PG I that also pose an inhalation toxicity hazard by limiting or prohibiting their transportation on aircraft. As written, the regulatory instruction for the HMT might inadvertently remove the PG II and III entries for ''UN2923, Corrosive solids, toxic, n.o.s.'' Therefore, the regulatory instructions need to be revised to ensure that PG II and III for ''UN2923, Corrosive solids, toxic, n.o.s.'' are not deleted from the HMT. To meet the original intent of HM–215Q to harmonize with international standards, PHMSA is correcting this error in this notice. *See* ''Section III. Corrections.''

• *UN0512, Detonators, electronic programmable for blasting:* In HM–215Q, PHMSA made a revision to the entry ''UN0512, Detonators, electronic programmable for blasting.'' In the 2022 HM–215P final rule, PHMSA added three new entries for electronic detonators to distinguish them from electric detonators, which have different functioning characteristics but similar regulatory provisions for their transport and incorrectly assigned an obsolete special provision, Special Provision 103. In HM–215Q, PHMSA removed the reference to Special Provision 103 in Column 7 for UN0512 and replaced it with Special Provision 148 consistent with the entry of UN0255. However, in making this revision in HM–215Q, PHMSA inadvertently made the word ''electronic'' in ''UN0512, Detonators, electronic programmable for blasting'' in italics. Proper shipping names listed in the HMT are limited to those shown in Roman type (not italics). To meet the original intent of HM–215Q to harmonize with international standards, PHMSA is correcting this error in this notice. *See* ''Section III. Corrections.''

• *UN3148, Water-reactive liquid, n.o.s.:* In HM–215Q, PHMSA made corrections to multiple HMT entries that were inadvertently modified in previous rulemakings. Specifically, for the PG II and III entries for ''UN3129, Water-reactive liquid, corrosive, n.o.s.'' and ''UN3148, Water-reactive liquid, n.o.s.,'' the references to the exceptions in § 173.151 in Column 8A were removed and replaced with the word ''None.'' In doing so however, PHMSA inadvertently made revisions to the PG II entry for ''UN3148, Water-reactive liquid, n.o.s.,'' that were not intended. This includes inadvertent revisions to columns 7, 8B, 8C, 9A, and 9B for the PG II entry for ''UN3148, Water-reactive liquid, n.o.s.'' To meet the original intent of HM–215Q to harmonize with international standards, PHMSA is correcting this error in this notice. *See* ''Section III. Corrections.''

II. Regulatory Analyses and Notices

A. Statutory/Legal Authority

Statutory authority for this notice's corrections to the final rule, as with the final rule itself, is provided by the Federal hazardous materials transportation law (49 U.S.C. 5101 *et seq.*). The Secretary delegated the authority granted in the Federal hazardous materials transportation law to the PHMSA Administrator at 49 CFR 1.97(b).

PHMSA finds it has good cause to make the technical corrections herein without notice and comment pursuant to Section 553(b) of the Administrative Procedure Act (APA, 5 U.S.C. 551, *et seq.*). Section 553(b)(B) of the APA provides that, when an agency for good cause finds that notice and public procedure are impracticable, unnecessary, or contrary to the public interest, the agency may issue a rule without providing notice and an opportunity for public comment. As explained above, the corrections here consists of technical correction to amend the amendatory instruction 19c. to § 173.225 which (as published in the **Federal Register**) inadvertently would not make a necessary revision to an entry in Table 4 to paragraph (g), as well as cure inadvertent omissions of current HMT fields. The publication of these corrections are needed to ensure that § 173.225 and the HMT continue to read as intended; these technical corrections make no substantive changes to the final rule but merely facilitate its implementation. Because the final rule is the product of an extensive administrative record with numerous opportunities—including through written comments—for public comment, PHMSA finds that additional comment on the technical corrections herein is unnecessary.

The May 10, 2024, effective date of the corrections contained in this notice is authorized under both Section 553(d)(1) and (3) of the APA. Section 553(d)(1) provides that a rule should take effect ''not less than 30 days'' after publication in the **Federal Register** except for ''a substantive rule which grants or recognizes an exemption or relieves a restriction,'' while Section 553(d)(3) allows for earlier effectiveness for good cause found by the agency and published within the rule. 5 U.S.C. 553(d)(1), (3). ''The purpose of the thirty-day waiting period is to give affected parties a reasonable time to adjust their behavior before the final rule takes effect.'' *Omnipoint Corp.* v. *F.C.C.,* 78 F.3d 620, 630 (D.C. Cir. 1996). Since this final rule has not yet taken effect, the impact on affected parties is minimal and such parties will not be adversely impacted by the shortened period before the corrections become effective. The correction of amendatory instruction 19c. ensures that the intended regulatory language at Table 4 to paragraph (g) in § 173.225 will be codified in regulation, and other

corrections restore HMT fields that could be inadvertently deleted by the final rule; in accordance with 5 U.S.C. 553(d)(1), those corrections will be effective May 10, 2024. Moreover, PHMSA finds that good cause under Section 553(d)(3) supports making the revisions effective May 10, 2024, because the corrections contained in this notice are entirely consistent with the final rule—which itself was published in April 2024—and help promote timely compliance with the final rule's requirements before its May 10, 2024, effective date.

B. Executive Order 12866 and 14094, and DOT Regulatory Policies and Procedures

These corrections have been evaluated in accordance with existing policies and procedures and are not considered significant under Executive Order 12866 (''Regulatory Planning and Review''),[2] Executive Order 14094 (''Modernizing Regulatory Review''),[3] and DOT Order 2100.6A (''Rulemaking and Guidance Procedures''); therefore, this notice has not been reviewed by the Office of Management and Budget (OMB) under Executive Order 12866. PHMSA finds that the technical corrections herein (in all respects consistent with the final rule) neither impose incremental compliance costs nor adversely affect safety. Overall, PHMSA expects any impacts on the expected costs and benefits of the final rule will be negligible.

C. Executive Order 13132

PHMSA has analyzed these corrections in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism'')[4] and the Presidential memorandum (''Preemption'') that was published in the **Federal Register** on May 22, 2009.[5] Executive Order 13132 requires agencies to assure meaningful and timely input by state and local officials in the development of regulatory policies that may have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.'' The technical corrections herein are consistent with, and merely facilitate compliance with, the final rule, and do not have any substantial direct effect on the states, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government beyond what was accounted for in the final rule. This notice does not contain any provision that imposes any substantial direct compliance costs on state and local governments, nor any new provision that preempts state law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

D. Executive Order 13175

These corrections were analyzed in accordance with the principles and criteria contained in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'')[6] and DOT Order 5301.1A (''Department of Transportation Tribal Consultation Policies and Procedures''). Executive Order 13175 and DOT Order 5301.1A require DOT Operating Administrations to assure meaningful and timely input from Native American tribal government representatives in the development of rules that significantly or uniquely affect tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities, or the relationship and distribution of power between the Federal Government and Native American tribes. Because the technical corrections herein do not have Tribal implications or impose substantial direct compliance costs on Indian Tribal governments, the funding and consultation requirements of Executive Order 13175 do not apply.

E. Regulatory Flexibility Act, Executive Order 13272, and DOT Policies and Procedures

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires agencies to review regulations to assess their impact on small entities unless the agency head certifies that a rulemaking will not have a significant economic impact on a substantial number of small entities including small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations under 50,000. The Regulatory Flexibility Act directs agencies to establish exceptions and differing compliance standards for small businesses, where possible to do so and still meet the objectives of applicable regulatory statutes. Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'')[7] requires agencies to establish procedures and policies to promote compliance with the Regulatory Flexibility Act and to ''thoroughly review draft rules to assess and take appropriate account of the potential impact'' of the rules on small businesses, governmental jurisdictions, and small organizations. The DOT posts its implementing guidance on a dedicated web page.[8]

This corrections document was—like the final rule—developed in accordance with Executive Order 13272 and with DOT's procedures and policies to promote compliance with the Regulatory Flexibility Act to ensure that potential impacts of draft rules on small entities are properly considered. These corrections—like the final rule—facilitate the transportation of hazardous materials in international commerce by providing consistency with international standards. Those corrections apply to offerors and carriers of hazardous materials, some of whom are small entities, such as chemical manufacturers, users, and suppliers; and packaging manufacturers, distributors, and training companies. As discussed at length in the regulatory impact analysis (RIA) that accompanied the final rule and was posted in the rulemaking docket, the amendments in the final rule should result in net cost savings that will ease the regulatory compliance burden for those and other entities engaged in domestic and international commerce, including trans-border shipments within North America. Additionally, the changes in the final rule will relieve U.S. companies—including small entities competing in foreign markets—from the burden of complying with a dual system of regulations. Therefore, PHMSA expects that these corrections—like the amendments in the final rule—will not have a significant economic impact on a substantial number of small entities. Because the technical corrections herein will impose no new incremental compliance costs, PHMSA understands the analysis in the RIA remains unchanged.

F. Paperwork Reduction Act

The corrections in this notice impose no new or revised information collection requirements beyond those discussed in the final rule.

G. Unfunded Mandates Reform Act of 1995

PHMSA analyzed the corrections in this notice under the factors in the

[2] 58 FR 51735 (Oct. 4, 1993).

[3] 88 FR 21879 (April 11, 2023).

[4] 64 FR 43255 (Aug. 10, 1999).

[5] 74 FR 24693 (May 22, 2009).

[6] 65 FR 67249 (Nov. 9, 2000).

[7] 67 FR 53461 (Aug. 16, 2002).

[8] DOT, ''Rulemaking Requirements Related to Small Entities,'' *https://www.transportation.gov/regulations/rulemaking-requirements-concerning-small-entities* (last accessed June 17, 2021).

Unfunded Mandates Reform Act of 1995 (UMRA, 2 U.S.C. 1501 *et seq.*) and determined that the corrections to the final rule herein do not impose enforceable duties on state, local, or tribal governments or on the private sector of $100 million or more, adjusted for inflation, in any one year. PHMSA prepared an analysis of the UMRA considerations in the final RIA for the final rule, which is available in the docket for the rulemaking. Because the corrections herein will impose no new incremental compliance costs, PHMSA understands the analysis in that UMRA discussion for the final rule remains unchanged.

H. Environmental Assessment

The National Environmental Policy Act of 1969 (NEPA, 42 U.S.C. 4321 *et seq.*) requires federal agencies to prepare a detailed statement on major Federal actions significantly affecting the quality of the human environment. PHMSA analyzed the final rule in accordance with NEPA, implementing Council on Environmental Quality regulations (40 CFR parts 1500–1508), and DOT implementing policies (DOT Order 5610.1C, ''Procedures for Considering Environmental Impacts'') and determined the final rule would have not significantly impact on the human environment. The corrections to the final rule in this notice have no effect on PHMSA's earlier NEPA analysis as they are consistent, and merely facilitate compliance with, the final rule.

I. Privacy Act

In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to inform its rulemaking process. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *www.dot.gov/privacy.*

J. Executive Order 13609 and International Trade Analysis

Under Executive Order 13609 (''Promoting International Regulatory Cooperation''),[9] agencies must consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements. The corrections to the final rule in this notice do not impact international trade.

K. National Technology Transfer and Advancement Act

The National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) directs federal agencies to use voluntary consensus standards in their regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* specification of materials, test methods, or performance requirements) that are developed or adopted by voluntary consensus standard bodies. The final rule involved multiple voluntary consensus standards which were discussed at length in the discussion on § 171.7. The corrections herein do not change the final rule's analysis.

L. Executive Order 13211

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') [10] requires federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' The corrections herein do not invoke any issues under Executive Order 13211.

M. Cybersecurity and Executive Order 14028

Executive Order 14028 (''Improving the Nation's Cybersecurity'') [11] directed the federal government to improve its efforts to identify, deter, and respond to ''persistent and increasingly sophisticated malicious cyber campaigns.'' The corrections herein do not invoke any cybersecurity issues.

N. Severability

These corrections do not present any issues with severability.

III. Corrections

PHMSA makes corrections to the regulatory text of the final rule document. PHMSA is correctly revising the § 172.101 HMT entries for the hazardous materials discussed above in Section I. Additionally, PHMSA is correcting the amendatory instruction 19c.

■ In FR Doc. 2024–06956, appearing on page 25434 in the **Federal Register** of Wednesday, April 10, 2024, the following corrections are made:

■ a. On page 25474, revise the entry for ''Articles containing miscellaneous dangerous goods, n.o.s.'';

■ b. On page 25474, revise the entry for ''Articles containing non-flammable, non-toxic gas, n.o.s.'';

■ c. On page 25474, revise the entry for ''Corrosive liquids, toxic, n.o.s.'';

■ d. On page 25474, add seven stars in between the ''Corrosive liquids, toxic, n.o.s.'' entry and the ''Corrosive solids, toxic, n.o.s.'' entry;

■ e. On page 25474, revise the entry for ''Corrosive solids, toxic, n.o.s.'';

■ f. On page 25474, revise the entry for ''Detonators, electronic programmable for blasting''; and

■ g. On page 25475, revise the entry for ''Water-reactive liquid, n.o.s.''.

The corrections read as follows:

§ 172.101 [Corrected]

* * * * *

§ 172.101 Hazardous Materials Table

BILLING CODE 4910–60–P

[9] 77 FR 26413 (May 4, 2012).

[10] 66 FR 28355 (May 22, 2001).

[11] 86 FR 26633 (May 17, 2021).

							(8)			(9)		(10)	
							Packaging (§ 173.***)			Quantity limitations (see §§ 173.27 and 175.75)		Vessel stowage	
Symbols (1)	Hazardous materials descriptions and proper shipping names (2)	Hazard class or division (3)	Identification Numbers (4)	PG (5)	Label Codes (6)	Special Provisions (§ 172.102) (7)	Exceptions (8A)	Non-bulk (8B)	Bulk (8C)	Passenger aircraft/rail (9A)	Cargo aircraft only (9B)	Location (10A)	Other (10B)
	*		*		*		*		*		*		*
G	Articles containing miscellaneous dangerous goods, n.o.s.	9	UN3548		9	391, A224	None	232	232	Forbidden	Forbidden	A	
G	Articles containing non-flammable, non-toxic gas, n.o.s.	2.2	UN3538		2.2	391, 396, A225	None	232	232	Forbidden	Forbidden	A	
	*		*		*		*		*		*		*
G	Corrosive liquids, toxic, n.o.s.	8	UN2922	I	8, 6.1	A4, A7, B10, T14, TP2, TP13, TP27	None	201	243	0.5 L	2.5 L	B	40
				II	8, 6.1	B3, IB2, T7, TP2	154	202	243	1 L	30L	B	40
				III	8, 6.1	IB3, T7, TP1, TP28	154	203	241	5 L	60L	B	40
	*		*		*		*		*		*		*
G	Corrosive solids, toxic, n.o.s.	8	UN2923	I	8, 6.1	A5, IB7, T6, TP33	None	211	242	1 kg	25 kg	B	40
				II	8, 6.1	IB8, IP2, IP4, T3, TP33	154	212	240	15 kg	50 kg	B	40
				III	8, 6.1	IB8, IP3, T1, TP33	154	213	240	25 kg	100 kg	B	40
	*		*		*		*		*		*		*
	Detonators, electronic *programmable for blasting*	1.4B	UN0512		1.4B	148	63(f), 63(g)	62	None	Forbidden	75 kg	05	25
	*		*		*		*		*		*		*
G	Water-reactive liquid, n.o.s.	4.3	UN3148	I	4.3	T13, TP2, TP7, W31	None	201	244	Forbidden	1 L	E	13, 40, 148
				II	4.3	IB1, T7, TP2, TP7, W31	151	202	243	1 L	5 L	E	13, 40, 148
				III	4.3	IB2, T7, TP2, TP7, W31	151	203	242	5 L	60 L	E	13, 40, 148
	*		*		*		*		*		*		*

§ 173.225 [Corrected]

■ 2. On page 25481, in part 173, in amendment 19c., the instruction ''Revise newly designated table 4 to paragraph (g).:'' is corrected to read ''In newly designated table 4 to paragraph (g), under UN No. 3109, and above ''tert-Butyl hydroperoxide, not more than 72% with water'' add an entry for ''tert-Butyl hydroperoxide, not more than 56% with diluent type B[2]'' and revise the Notes after newly designated table 4 to paragraph (g) to read as follows''.

Issued in Washington, DC, on May 3, 2024, under authority delegated in 49 CFR 1.97.

Tristan H. Brown,

Deputy Administrator, Pipeline and Hazardous Materials Safety Administration.

[FR Doc. 2024–10098 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–60–C

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 679

[Docket No. 240227–0061; RTID 0648–XD692]

Fisheries of the Exclusive Economic Zone Off Alaska; Pacific Cod by Vessels Using Jig Gear in the Central Regulatory Area of the Gulf of Alaska

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Temporary rule; closure.

SUMMARY: NMFS is prohibiting directed fishing for Pacific cod by vessels using jig gear in the Central Regulatory Area of the Gulf of Alaska (GOA). This action is necessary to prevent exceeding the A season allowance of the 2024 total allowable catch (TAC) of Pacific cod by vessels using jig gear in the Central Regulatory Area of the GOA.

DATES: Effective 1200 hours, Alaska local time (A.l.t.), May 6, 2024, through 1200 hours, A.l.t., June 10, 2024.

FOR FURTHER INFORMATION CONTACT: Abby Jahn, 907–586–7416.

SUPPLEMENTARY INFORMATION: NMFS manages the groundfish fishery in the GOA exclusive economic zone according to the Fishery Management Plan for Groundfish of the Gulf of Alaska (FMP) prepared by the North Pacific Fishery Management Council under authority of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). Regulations governing fishing by U.S. vessels in accordance with the FMP appear at subpart H of 50 CFR part 600 and 50 CFR part 679.

The A season allowance of the 2024 Pacific cod TAC apportioned to vessels using jig gear in the Central Regulatory Area of the GOA is 185 metric tons (mt) as established by the final 2024 and 2025 harvest specifications for groundfish in the GOA (89 FR 15484, March 4, 2024).

In accordance with § 679.20(d)(1)(i), the Regional Administrator has determined that the A season allowance of the 2024 Pacific cod TAC apportioned to vessels using jig gear in the Central Regulatory Area of the GOA will soon be reached. Therefore, the Regional Administrator is establishing a directed fishing allowance of 93 mt and is setting aside the remaining 0 mt as bycatch to support other anticipated groundfish fisheries. In accordance with § 679.20(d)(1)(iii), the Regional Administrator finds that this directed fishing allowance has been reached. Consequently, NMFS is prohibiting directed fishing for Pacific cod by vessels using jig gear in the Central Regulatory Area of the GOA.

While this closure is effective, the maximum retainable amounts at § 679.20(e) and (f) apply at any time during a trip.

Classification

NMFS issues this action pursuant to section 305(d) of the Magnuson-Stevens Act. This action is required by 50 CFR part 679, which was issued pursuant to section 304(b), and is exempt from review under Executive Order 12866.

Pursuant to 5 U.S.C. 553(b)(B), there is good cause to waive prior notice and an opportunity for public comment on this action, as notice and comment would be impracticable and contrary to the public interest, as it would prevent NMFS from responding to the most recent fisheries data in a timely fashion, and would delay the closure of Pacific cod by vessels using jig gear in the Central Regulatory Area of the GOA. NMFS was unable to publish a notice providing time for public comment because the most recent, relevant data only became available as of May 3, 2024.

The Assistant Administrator for Fisheries, NOAA also finds good cause to waive the 30-day delay in the effective date of this action under 5 U.S.C. 553(d)(3). This finding is based upon the reasons provided above for waiver of prior notice and opportunity for public comment.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: May 6, 2024.

Karen H. Abrams,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2024–10151 Filed 5–6–24; 4:15 pm]

BILLING CODE 3510–22–P

Proposed Rules

Federal Register
Vol. 89, No. 91
Thursday, May 9, 2024

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2024–0396]

RIN 1625–AA87

Security Zone, Lake Erie, Mentor (Mentor Headlands), Ohio

AGENCY: Coast Guard, DHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard is proposing to establish a temporary security zone for certain waters of Lake Erie off Mentor Headlands Beach State Park, Mentor, Ohio. This action is necessary to provide offshore security for motion picture production activity on the Mentor Headlands Beach from June 17 through June 18, and June 20 through June 21, 2024. This proposed rulemaking would prohibit persons and vessels from entering this security zone unless authorized by the Captain of the Port Sector Eastern Great Lakes or a designated representative. We invite your comments on this proposed rulemaking.

DATES: Comments and related material must be received by the Coast Guard on or before June 10, 2024.

ADDRESSES: You may submit comments identified by docket number USCG–2024–0396 using the Federal Decision-Making Portal at *https://www.regulations.gov.* See the ''Public Participation and Request for Comments'' portion of the **SUPPLEMENTARY INFORMATION** section for further instructions on submitting comments. This notice of proposed rulemaking with its plain-language, 100-word-or-less proposed rule summary will be available in this same docket.

FOR FURTHER INFORMATION CONTACT: If you have questions about this proposed rulemaking, contact Cody Mayrer with the U.S. Coast Guard Marine Safety Unit Cleveland's Waterways Management Division; via telephone at 216–937–0111, or by email at *D09-SMB-MSUCLEVELAND-WWM@uscg.mil.*

SUPPLEMENTARY INFORMATION:

I. Table of Abbreviations

CFR Code of Federal Regulations
DHS Department of Homeland Security
FR Federal Register
NPRM Notice of proposed rulemaking
§ Section
U.S.C. United States Code

II. Background, Purpose, and Legal Basis

On February 27, 2024, S&K Productions notified the U.S. Coast Guard that it will be filming a motion picture on the Mentor Headlands Beach State Park in Mentor, Ohio from June 17 through June 18, and from June 20 through June 21, 2024, with rain dates of June 24–28, 2024. The Captain of the Port Sector Eastern Great Lakes (COTP) has determined that a security zone covering certain navigable waters of Lake Erie is needed to protect life and property during the S&K Productions' filming of project ''Genesis''.

The purpose of this rulemaking is to ensure offshore security of the film production personnel, sets, and equipment during production activity. The Coast Guard is proposing this rulemaking under its authority granted in 46 U.S.C. 70034.

III. Discussion of Proposed Rule

The COTP is proposing to establish the following security zone covering certain navigable waters of Lake Erie off the Mentor Headlands, Mentor, Ohio. The duration and location of this zone is intended to protect personnel, sets, and equipment during the S&K Productions' filming project. The zone may require enforcement beyond the stated times if the filming runs into unforeseen delays. Rain dates have been designated for June 24–28, 2024. No vessel or person would be permitted to enter the security zone listed directly below without permission from the COTP or a designated representative. The regulatory text we are proposing appears at the end of this document.

The boundary of the 500-yard offshore security zone from the Mentor Headlands Beach State Park forms a rectangle with the four corners of the polygon located in the following coordinates:

(1) 41°45′17″ N, 081°17′41″ W;
(2) 41°45′27″ N, 081°17′57″ W;
(3) 41°46′18″ N, 081°17′02″ W; and
(4) 41°46′01″ N, 081°16′49″ W (NAD 83).

IV. Regulatory Analyses

We developed this proposed rule after considering numerous statutes and Executive orders related to rulemaking. Below we summarize our analyses based on a number of these statutes and Executive orders, and we discuss First Amendment rights of protestors.

A. Regulatory Planning and Review

Executive Orders 12866 and 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits. This NPRM has not been designated a ''significant regulatory action,'' under section 3(f) of Executive Order 12866, as amended by Executive Order 14094 (Modernizing Regulatory Review). Accordingly, the NPRM has not been reviewed by the Office of Management and Budget (OMB).

This regulatory action determination is based on is based on size, location, and duration of the proposed rule. These security zone would restrict navigation through Lake Erie offshore of the Mentor Headlands Beach State Park for 13 hours each day, for a total of four days. 52 hours in all.

B. Impact on Small Entities

The Regulatory Flexibility Act of 1980, 5 U.S.C. 601–612, as amended, requires Federal agencies to consider the potential impact of regulations on small entities during rulemaking. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000. The Coast Guard certifies under 5 U.S.C. 605(b) that this proposed rule would not have a significant economic impact on a substantial number of small entities.

While some owners or operators of vessels intending to transit the security zone may be small entities, for the reasons stated in section IV.A above, this proposed rule would not have a significant economic impact on any vessel owner or operator.

If you think that your business, organization, or governmental

jurisdiction qualifies as a small entity and that this proposed rule would have a significant economic impact on it, please submit a comment (see **ADDRESSES**) explaining why you think it qualifies and how and to what degree this rule would economically affect it.

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this proposed rule. If the proposed rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please call or email the person listed in the **FOR FURTHER INFORMATION CONTACT** section. The Coast Guard will not retaliate against small entities that question or complain about this proposed rule or any policy or action of the Coast Guard.

C. Collection of Information

This proposed rule would not call for a new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

D. Federalism and Indian Tribal Governments

A rule has implications for federalism under Executive Order 13132 (Federalism), if it has a substantial direct effect on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government. We have analyzed this proposed rule under that Order and have determined that it is consistent with the fundamental federalism principles and preemption requirements described in Executive Order 13132.

Also, this proposed rule does not have tribal implications under Executive Order 13175 (Consultation and Coordination with Indian Tribal Governments) because it would not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes. If you believe this proposed rule has implications for federalism or Indian tribes, please call or email the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

E. Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any one year. Though this proposed rule would not result in such an expenditure, we do discuss the potential effects of this proposed rule elsewhere in this preamble.

F. Environment

We have analyzed this proposed rule under Department of Homeland Security Directive 023–01, Rev. 1, associated implementing instructions, and Environmental Planning COMDTINST 5090.1 (series), which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (42 U.S.C. 4321–4370f), and have made a preliminary determination that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This proposed rule involves a security zone offshore of the Mentor Headlands State Park Beach lasting 13 hours each day for a total of four days. Normally such actions are categorically excluded from further review under paragraph L60a of Appendix A, Table 1 of DHS Instruction Manual 023–01–001–01, Rev. 1. A preliminary Record of Environmental Consideration supporting this determination is available in the docket. For instructions on locating the docket, see the **ADDRESSES** section of this preamble. We seek any comments or information that may lead to the discovery of a significant environmental impact from this proposed rule.

G. Protest Activities

The Coast Guard respects the First Amendment rights of protesters. Protesters are asked to call or email the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places, or vessels.

V. Public Participation and Request for Comments

We view public participation as essential to effective rulemaking and will consider all comments and material received during the comment period. Your comment can help shape the outcome of this rulemaking. If you submit a comment, please include the docket number for this rulemaking, indicate the specific section of this document to which each comment applies, and provide a reason for each suggestion or recommendation.

Submitting comments. We encourage you to submit comments through the Federal Decision-Making Portal at *https://www.regulations.gov.* To do so, go to *https://www.regulations.gov,* type USCG–2024–0396 in the search box and click ''Search.'' Next, look for this document in the Search Results column, and click on it. Then click on the Comment option. If you cannot submit your material by using *https://www.regulations.gov,* call or email the person in the **FOR FURTHER INFORMATION CONTACT** section of this proposed rule for alternate instructions.

Viewing material in docket. To view documents mentioned in this proposed rule as being available in the docket, find the docket as described in the previous paragraph, and then select ''Supporting & Related Material'' in the Document Type column. Public comments will also be placed in our online docket and can be viewed by following instructions on the *https://www.regulations.gov* Frequently Asked Questions web page. Also, if you click on the Dockets tab and then the proposed rule, you should see a ''Subscribe'' option for email alerts. The option will notify you when comments are posted, or a final rule is published.

We review all comments received, but we will only post comments that address the topic of the proposed rule. We may choose not to post off-topic, inappropriate, or duplicate comments that we receive.

Personal information. We accept anonymous comments. Comments we post to *https://www.regulations.gov* will include any personal information you have provided. For more about privacy and submissions to the docket in response to this document, see DHS's eRulemaking System of Records notice (85 FR 14226, March 11, 2020).

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard is proposing to amend 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 46 U.S.C. 70034, 70051; 70124, 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation No. 00170.1, Revision No. 01.3.

■ 2. Add § 165.T09–0396 to read as follows:

§ 165.T09–0396 Security Zone; Mentor Headlands Beach, Mentor, Ohio.

(a) *Location.* The following area is a security zone: Mentor, OH. All U.S. waters of Lake Erie out to 500-yards from the shoreline at Mentor Headlands Beach State Park within a rectangle of which the four corners of the polygon are located in the following positions:

(1) 41°45′17″ N, 081°17′41″ W;

(2) 41°45′27″ N, 081°17′57″ W;

(3) 41°46′18″ N, 081°17′02″ W; and

(4) 41°46′01″ N, 081°16′49″ W (NAD 83).

(b) *Definitions*—(1) *Official Patrol Vessel* means a Coast Guard Patrol Commander, including a Coast Guard coxswain, petty officer, or other officer operating a Coast Guard vessel and a Federal, State, and local officer designated by or assisting the Captain of the Port Sector Eastern Great Lakes (COTP) in the enforcement of the regulations in this section.

(2) *Spectator* means all persons and vessels not registered with the production company as participants or official patrol vessels.

(3) *Rain date* refers to an alternate date and/or time in which the safety zone would be enforced in the event of inclement weather.

(c) *Regulations.* (1) The Coast Guard may patrol the security zone area under the direction of a designated Coast Guard Patrol Commander. The Patrol Commander may be contacted on Channel 16 VHF–FM (156.8 MHz) by the call sign ''PATCOM.''

(2) All persons and vessels not registered with the production company or official patrol vessels are considered spectators. The ''official patrol vessels'' consist of any Coast Guard, state or local law enforcement and production company provided vessels designated or assigned by the COTP Sector Eastern Great Lakes, to patrol the security zone.

(3) Spectator vessels desiring to transit the regulated area may do so only with prior approval of the Patrol Commander and when so directed by that officer and will be operated at a no wake speed in a manner which will not endanger anyone directly involved with the production or any other craft.

(4) No spectator shall anchor, block, loiter, or impede the through transit of official patrol vessels in the regulated area during the effective dates and times, unless cleared for entry by or through an official patrol vessel.

(5) The Patrol Commander may forbid and control the movement of all vessels in the regulated area. When hailed or signaled by an official patrol vessel, a vessel shall come to an immediate stop and comply with the directions given. Failure to do so may result in expulsion from the area, citation for failure to comply, or both.

(6) Any spectator vessel may anchor outside the regulated areas specified in this chapter, but may not anchor in, block, or loiter in a navigable channel.

(7) The Patrol Commander may terminate the filming or the operation of any vessel at any time it is deemed necessary for the protection of life and/or property.

(8) The Patrol Commander will terminate enforcement of the special regulations at the conclusion of the event.

(d) *Enforcement period.* This section will be enforced from 6:30 a.m. through 7:30 p.m. on June 17 through June 18, 2024, and from 2:30 p.m. through 3:30 a.m. on June 20 through June 21, 2024. Rain dates have been identified as June 24–28, 2024. Times of enforcement should these rain dates be necessary will be advertised through Local Notice to Mariners and Broadcast Notice to Mariners.

Dated: May 3, 2024.

S.M. Murray,

Commander, U.S. Coast Guard, Acting Captain of the Port Eastern Great Lakes.

[FR Doc. 2024–10125 Filed 5–8–24; 8:45 am]

BILLING CODE 9110–04–P

Notices

Federal Register
Vol. 89, No. 91
Thursday, May 9, 2024

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Commodity Credit Corporation

[Docket ID FSA–2024–0003]

Notice of Funds Availability; Organic Certification Cost Share Program (OCCSP)

AGENCY: Commodity Credit Corporation and Farm Service Agency, USDA.

ACTION: Notification of funding availability.

SUMMARY: The Farm Service Agency (FSA), on behalf of the Commodity Credit Corporation, is issuing this notice to announce the availability of cost share assistance through OCCSP for fiscal year (FY) 2024. FSA is giving the opportunity for State Agencies to apply for grant agreements to administrator the OCCSP program to establish agreements to provide cost share assistance to eligible producers and handlers and for producers and handlers to apply for OCCSP payment at FSA county office.

DATES: *Applications for State Agency Agreements:* FSA will accept applications from State Agencies to administer OCCSP for FY 2024 between the period of May 13, 2024, and October 31, 2024.

Producer and Handler Applications: FSA county offices will accept applications for OCCSP from producers and handlers for FY 2024 until October 31, 2024.

FOR FURTHER INFORMATION CONTACT: Chris Vazquez; telephone: (202) 923–1585; email: *christopher.vazquez@usda.gov.* Individuals who require alternative means for communication should contact the USDA Target Center at (202) 720–2600 (voice and text telephone (TTY)) or dial 711 for Telecommunications Relay service (both voice and text telephone users can initiate this call from any telephone).

SUPPLEMENTARY INFORMATION:

Background

OCCSP provides cost share assistance to producers and handlers of agricultural products for the costs of obtaining or maintaining organic certification under the National Organic Program (NOP).[1] The purpose of this NOFA is to announce the funding availability and application periods for FY 2024.

OCCSP is funded through two authorizations: (1) National Organic Certification Cost Share Program (National OCCSP) funds, and (2) Agricultural Management Assistance (AMA) funds. Section 102 of the Further Continuing Appropriations and Other Extensions Act, 2024 (Pub. L. 118–22) amended the Farm Security and Rural Investment Act of 2002 (7 U.S.C. 6523(d)(1)(C)) to provide $8 million[2] in National OCCSP funding for FY 2024. In addition, approximately $1.5 million in National OCCSP funding remains available from prior years. An additional $1 million[3] in AMA funding is authorized for each FY. (7 U.S.C. 1524).

On April 29, 2019, FSA published a notice in the **Federal Register** announcing general eligibility and administrative provisions for OCCSP for FY 2019 through 2023 (84 FR 17997–17999). For FY 2024, FSA will administer OCCSP according to the provisions that were applicable for FY 2019 through 2023, providing cost share assistance for 75 percent of an applicant's eligible expenses, up to $750 per scope, which is the maximum amount allowed by law.[4] Cost share assistance is provided on a first come, first served basis, until all available funds are obligated.

As in previous years, FSA will accept applications through FSA county offices and also partner with participating State agencies to administer the program through grant agreements.

Application Period for State Agencies and How To Submit an Application

FSA will accept applications from State Agencies from May 13, 2024, through October 31. 2024. To administer OCCSP for FY 2024, State Agencies must submit an Application for Federal Assistance (Standard Form 424 and 424A) electronically via *Grants.gov* (*https://www.grants.gov*) and enter into a grant agreement with FSA. State Agencies will refer to the Fiscal Year 2024 Full Notice of Funding Opportunity Announcement on *Grants.gov* for additional application requirements. For information on how to use *Grants.gov*, please access *https://www.grants.gov/applicants.*

Application Period for Producers and Handlers and How To Submit an Application

Producers and handlers may submit applications for eligible costs incurred in FY 2024 (the period of October 1, 2023, through September 30, 2024) to their FSA county office until October 31, 2024. The FSA county office locator is available in the ''Find Your Local Service Center'' section on *https://www.farmers.gov.*

Participating State Agencies will establish their own application process and deadlines, as specified in their grant agreements, and producers and handlers must submit an application package according to the instructions provided by the State Agency. A list of participating State Agencies will be available at *https://www.fsa.usda.gov/programs-and-services/occsp* after their agreements with FSA are finalized.

---

[1] USDA's Agricultural Marketing Service (AMS) administers the NOP, which was established under the Organic Foods Production Act of 1990 (7 U.S.C. 6501–6524). Information about organic standards, the certification process, and additional resources for organic producers is available at *https://www.farmers.gov/your-business/organic.* More information about OCCSP is available at *https://www.fsa.usda.gov/programs-and-services/occsp/index.*

[2] After sequestration of 5.7 percent, $7,544,000 in National OCCSP funding is available for FY 2024.

[3] After sequestration of 5.7 percent, $943,000 in AMA funding is available for FY 2024.

[4] On August 10, 2020, FSA announced in the **Federal Register** that the maximum amount of cost share for FY 2020 through 2023 would be 50 percent of an applicant's eligible expenses, up to $500 per scope, due to the limited amount of funding available and expected participation rates. (85 FR 48149–48150). For FY 2020 through 2022, FSA also provided cost share for eligible organic and transitional certification and education expenses through the Organic and Transitional Education and Certification Program (OTECP) in response to economic challenges due to the COVID–19 pandemic that made obtaining and renewing USDA organic certification financially challenging for many operations. On May 10, 2023, FSA announced that OCCSP funding was available for FY 2023 to increase the amount of cost share to 75 percent of eligible costs, up to $750 per scope. (See *https://www.usda.gov/media/press-releases/2023/05/10/usda-announces-new-steps-enhance-organic-markets-and-support.*)

Paperwork Reduction Act Requirements

There are no changes to the information collection request for OCCSP that has been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act. The OMB control number for the approval is 0560–0289.

Environmental Review

The environmental impacts have been considered in a manner consistent with the provisions of the National Environmental Policy Act (NEPA, 42 U.S.C. 4321–4347), the regulations of the Council on Environmental Quality (40 CFR parts 1500–1508), and the FSA regulation for compliance with NEPA (7 CFR part 799). The purpose of OCCSP is to provide cost share assistance to producers and handlers of agricultural products in obtaining organic certification. This NOFA merely announces funding availability and program deadlines for the 2024 program year. FSA is not making substantive changes to OCCSP.

As such, the Categorical Exclusions found at 7 CFR part 799.31 apply, specifically 7 CFR 799.31(b)(6)(iii) (that is, financial assistance to supplement income). No Extraordinary Circumstances (7 CFR 799.33) exist. As such, FSA has determined that this NOFA does not constitute a major Federal action that would significantly affect the quality of the human environment, individually or cumulatively. Therefore, FSA will not prepare an environmental assessment or environmental impact statement for this administrative action and this NOFA serves as documentation of the programmatic environmental compliance decision.

Federal Assistance Programs

The title and number of the Federal assistance program, as found in the Assistance Listings, to which this document applies are 10.171, Organic Certification Cost Share Program (OCCSP).

USDA Non-Discrimination Policy

In accordance with Federal civil rights law and U.S. Department of Agriculture (USDA) civil rights regulations and policies, USDA, its Agencies, offices, and employees, and institutions participating in or administering USDA programs are prohibited from discriminating based on race, color, national origin, religion, sex, gender identity (including gender expression), sexual orientation, disability, age, marital status, family or parental status, income derived from a public assistance program, political beliefs, or reprisal or retaliation for prior civil rights activity, in any program or activity conducted or funded by USDA (not all bases apply to all programs). Remedies and complaint filing deadlines vary by program or incident.

Individuals who require alternative means of communication for program information (for example, braille, large print, audiotape, American Sign Language, etc.) should contact the responsible Agency or the USDA TARGET Center at (202) 720–2600 (voice and text telephone (TTY)) or dial 711 for Telecommunications Relay Service (both voice and text telephone users can initiate this call from any telephone). Additionally, program information may be made available in languages other than English.

To file a program discrimination complaint, complete the USDA Program Discrimination Complaint Form, AD–3027, found online at *https://www.usda.gov/oascr/how-to-file-a-program-discrimination-complaint* and at any USDA office or write a letter addressed to USDA and provide in the letter all the information requested in the form. To request a copy of the complaint form, call (866) 632–9992. Submit your completed form or letter to USDA by: (1) mail to: U.S. Department of Agriculture, Office of the Assistant Secretary for Civil Rights, 1400 Independence Avenue SW, Washington, DC 20250–9410; (2) fax: (202) 690–7442; or (3) email: *program.intake@usda.gov.*

USDA is an equal opportunity provider, employer, and lender.

Zach Ducheneaux,

Administrator, Farm Service Agency and Executive Vice President, Commodity Credit Corporation.

[FR Doc. 2024–10172 Filed 5–8–24; 8:45 am]

BILLING CODE 3410–E2–P

DEPARTMENT OF AGRICULTURE

Rural Housing Service

[Docket No.: RHS–24–MFH–0010]

Notice of Solicitation of Applications for Section 514 Off-Farm Labor Housing Loans and Section 516 Off-Farm Labor Housing Grants for New Construction for Fiscal Year 2024; Correction

AGENCY: Rural Housing Service, USDA.

ACTION: Notice of solicitation of applications (NOSA); correction.

SUMMARY: The Rural Housing Service (RHS or Agency), a Rural Development (RD) agency of the United States Department of Agriculture (USDA), is correcting a notice of solicitation of applications (NOSA) that published in the **Federal Register** on April 19, 2024, entitled, ''Notice of Solicitation of Applications for Section 514 Off-Farm Labor Housing Loans and Section 516 Off-Farm Labor Housing Grants for New Construction for Fiscal Year 2024.'' The notice described the methods used to distribute funds, the pre-application and final application process, and submission requirements. The purpose of this document is to correct the inadvertent errors to the commitment letter requirements published in the **Federal Register** on April 19, 2024.

DATES: May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Jonathan Bell, Branch Director, Processing and Report Review Branch, Production and Preservation Division, Multifamily Housing Programs, Rural Development, United States Department of Agriculture, via email: *MFHprocessing1@usda.gov* or telephone: (202) 205–9217.

SUPPLEMENTARY INFORMATION:

Correction

In the **Federal Register** of April 19, 2024, in FR Doc. 2024–08155 (89 FR 28717), on page 28725, in the first column in the first paragraph (ii), correct the paragraph to read:

ii. All applications that propose the use of any leveraged funds should submit commitment letters with their application, if available. If the applicant is unable to secure third-party firm commitment letters within the twelve-month time frame, as specified in the award commitment, the application will be deemed incomplete, the award letter will be considered null and void, and the applicant will be notified in writing that the application will be rejected.

Joaquin Altoro,

Administrator, Rural Housing Service.

[FR Doc. 2024–10173 Filed 5–8–24; 8:45 am]

BILLING CODE 3410–XV–P

COMMISSION ON CIVIL RIGHTS

Notice of Public Meeting of the Hawai'i Advisory Committee

AGENCY: U.S. Commission on Civil Rights.

ACTION: Notice of webinar public forum.

SUMMARY: Notice is hereby given, pursuant to the provisions of the rules and regulations of the U.S. Commission on Civil Rights (Commission) and the Federal Advisory Committee Act (FACA), that the Hawai'i Advisory Committee (Committee) to the U.S.

Commission on Civil Rights will convene by ZoomGov on Wednesday, May 29, 2024, from 6 p.m. to 7 p.m. HST, is to collect public comment from impacted individuals who have lived experiences related to the Committee's project.

DATES: Wednesday, May 29, 2024, from 6 p.m.–7 p.m. Hawai'i standard time.

ADDRESSES: The meeting will be held via Zoom Webinar.

Registration Link (Audio/Visual): https://www.zoomgov.com/webinar/register/WN_u92J41dkRP-3CWlqnXs15w.

Join by Phone (Audio Only): (833) 435–1820 USA Toll Free; Webinar ID: 161 099 6483.

FOR FURTHER INFORMATION CONTACT: Kayla Fajota, Designated Federal Officer (DFO) at *kfajota@usccr.gov* or (434) 515–2395.

SUPPLEMENTARY INFORMATION: Committee meetings are available to the public through the videoconference link above. Any interested member of the public may listen to the meeting. An open comment period will be provided to allow members of the public to make a statement as time allows. Per the Federal Advisory Committee Act, public minutes of the meeting will include a list of persons who are present at the meeting. If joining via phone, callers can expect to incur regular charges for calls they initiate over wireless lines, according to their wireless plan. The Commission will not refund any incurred charges. Closed captions will be provided for individuals who are deaf, hard of hearing, or who have certain cognitive or learning impairments. To request additional accommodations, please email Angelica Trevino, Support Services Specialists, at *atrevino@usccr.gov* at least 10 business days prior to the meeting.

Members of the public are entitled to make comments during the open period at the end of the meeting. Members of the public may also submit written comments; the comments must be received in the Regional Programs Unit within 30 days following the meeting. Written comments may be emailed to Kayla Fajota (DFO) at *kfajota@usccr.gov.*

Records generated from this meeting may be inspected and reproduced at the Regional Programs Coordination Unit Office, as they become available, both before and after the meeting. Records of the meetings will be available via *www.facadatabase.gov* under the Commission on Civil Rights, Hawai'i Advisory Committee link. Persons interested in the work of this Committee are directed to the Commission's website, *http://www.usccr.gov,* or may contact the Regional Programs Coordination Unit at *atrevino@usccr.gov.*

Agenda:

I. Welcome and Roll Call
II. Chair Remarks
III. Public Comment
IV. Next Steps
V. Adjournment

Dated: May 6, 2024.

David Mussatt,

Supervisory Chief, Regional Programs Unit.

[FR Doc. 2024–10174 Filed 5–8–24; 8:45 am]

BILLING CODE P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Emerging Technology Technical Advisory Committee; Notice of Partially Closed Meeting

The Emerging Technology Technical Advisory Committee (ETTAC) will meet on May 23 and 24, 2024, at 9:00 a.m.-3:00 p.m., (Eastern Daylight Time) in the Herbert C. Hoover Building, Room 3884, 1401 Constitution Avenue NW, Washington, DC (enter through Main Entrance on 14th Street between Constitution and Pennsylvania Avenues). The Committee's primary focus is the identification of emerging and foundational technologies that may be developed over a period of five to ten years with potential dual-use applications as early as possible in their developmental stages both within the United States and abroad, and any other matters relating to actions designed to carry out the policy set forth in Section 1752(1)(A) of the Export Control Reform Act. The purpose of the meeting is to have Committee members and U.S. Government representatives mutually review updated technical data and policy-driving information that has been gathered.

Agenda

May 23, 2024

Open Session

1. Opening remarks by the Chairman, Opening remarks by the Bureau of Industry and Security
2. Opening remarks by BIS Export Administration Leadership
3. Department of Commerce Updates
4. Regulations Update
5. Office of Science and Technology Policy Critical and Emerging Technologies List 2024 Updates
6. Emerging Technology Committee Updates
7. Additional Guest Speakers/ Presentations by the Public

May 24, 2024

Closed Session

8. Discussion of matters determined to be exempt from the open meeting and public participation requirements found in sections 1009(a)(1) and 1009(a)(3) of the Federal Advisory Committee Act (FACA) (5 U.S.C. 1001–1014). The exemption is authorized by section 1009(d) of the FACA, which permits the closure of advisory committee meetings, or portions thereof, if the head of the agency to which the advisory committee reports determines such meetings may be closed to the public in accordance with subsection (c) of the Government in the Sunshine Act (5 U.S.C. 552b(c)). In this case, the applicable provisions of 5 U.S.C. 552b(c) are subsection 552b(c)(4), which permits closure to protect trade secrets and commercial or financial information that is privileged or confidential, and subsection 552b(c)(9)(B), which permits closure to protect information that would be likely to significantly frustrate implementation of a proposed agency action were it to be disclosed prematurely. The closed session of the meeting will involve committee discussions and guidance regarding U.S. Government strategies and policies.

The open session will be accessible via teleconference. To join the conference, submit inquiries to Ms. Yvette Springer at *Yvette.Springer@bis.doc.gov* no later than May 16, 2024.

A limited number of seats will be available for the public session. Reservations are not accepted.

To the extent that time permits, members of the public may present oral statements to the Committee. The public may submit written statements at any time before or after the meeting. However, to facilitate distribution of materials to the Committee members, the Committee suggests that members of the public forward their materials prior to the meeting to Ms. Springer via email.

The Deputy Assistant Secretary for Administration Performing the non-exclusive functions and duties of the Chief Financial Officer with the concurrence of the delegate of the General Counsel, formally determined on April 29, 2024, pursuant to 5 U.S.C. 1009(d)), that the portion of the meeting dealing with pre-decisional changes to the Commerce Control List and the U.S. export control policies shall be exempt from the provisions relating to public meetings found in 5 U.S.C. 1009(a)(1) and 1009(a)(3). The remaining portions of the meeting will be open to the public.

For more information, contact Ms. Springer via email.

Yvette Springer,

Committee Liaison Officer.

[FR Doc. 2024–10119 Filed 5–8–24; 8:45 am]

BILLING CODE 3510–JT–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–028]

Hydrofluorocarbon Blends From the People's Republic of China: Preliminary Results and Partial Rescission of Antidumping Duty Administrative Review; 2022–2023

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) preliminarily determines that no companies under review qualify for a separate rate and that these companies are, therefore, considered to be part of the People's Republic of China (China)-wide entity. Additionally, Commerce is partially rescinding this review with respect to: companies for which all review requests were timely withdrawn; and a company with no entries of subject merchandise during the period of review (POR), August 1, 2022, through July 31, 2023. Interested parties are invited to comment on these preliminary results.

DATES: Applicable May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Melissa Porpotage, AD/CVD Operations, Office IX, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–1413.

SUPPLEMENTARY INFORMATION:

Background

On August 2, 2023, Commerce published a notice of opportunity to request an administrative review of the antidumping duty order on hydrofluorocarbon (HFC) blends from China.[1] Commerce received timely requests for an administrative review from the American HFC Coalition (the petitioner), and two Chinese companies. On October 18, 2023, Commerce published in the **Federal Register** a notice of initiation of an administrative review of the *Order* for the period August 1, 2022, through July 31, 2023, covering 19 companies, in accordance with section 751(a) of the Tariff Act of 1930, as amended (the Act) and 19 CFR 351.221(c)(1)(i).[2]

On December 4 and 8, 2023, the two Chinese companies that requested their own reviews, Zhejiang Sanmei Chemical Ind. Co., Ltd. (Zhejiang Sanmei) and ICool Chemical Co., Ltd. (ICool Chemical), filed timely withdrawals of their respective review requests.[3] On January 16, 2024, the petitioner filed a timely withdrawal of its review request for Zhejiang Sanmei.[4] Therefore, because all review requests for Zhejiang Sanmei and ICool Chemical have been withdrawn, Commerce is rescinding the review for these the two companies, as discussed below.

Finally, on January 16, 2024, we issued a memorandum notifying interested parties of our intent to rescind the review of certain companies subject to the review because they had no suspended entries during the POR.[5] We received no comments from interested parties on our intent to rescind.

Respondent Selection

On October 25, 2023, Commerce released U.S. Customs and Border Protection (CBP) entry data in order to select respondents for individual examination.[6] On November 1, 2023, we received comments regarding respondent selection from the petitioner.[7] However, we did not select any mandatory respondents for individual examination because only Zhejiang Sanmei and ICool Chemical timely filed separate rate applications and were, therefore, eligible for individual examination. However, as noted above, we are rescinding this review for Zhejiang Sanmei and ICool Chemical. No other company under review timely filed a separate rate application and/or certification; therefore, no company remaining under review is eligible for individual examination.[8] As such, there is no decision memorandum accompanying this notice.

Scope of the Order

The products subject to the *Order* are HFC blends. HFC blends covered by the scope are R–404A, a zeotropic mixture consisting of 52 percent 1,1,1-Trifluoroethane, 44 percent Pentafluoroethane, and 4 percent 1,1,1,2-Tetrafluoroethane; R–407A, a zeotropic mixture of 20 percent Difluoromethane, 40 percent Pentafluoroethane, and 40 percent 1,1,1,2-Tetrafluoroethane; R–407C, a zeotropic mixture of 23 percent Difluoromethane, 25 percent Pentafluoroethane, and 52 percent 1,1,1,2-Tetrafluoroethane; R–410A, a zeotropic mixture of 50 percent Difluoromethane and 50 percent Pentafluoroethane; and R–507A, an azeotropic mixture of 50 percent Pentafluoroethane and 50 percent 1,1,1-Trifluoroethane also known as R–507. The foregoing percentages are nominal percentages by weight. Actual percentages of single component refrigerants by weight may vary by plus or minus two percent points from the nominal percentage identified above.[9]

Any blend that includes an HFC component other than R–32, R–125, R–143a, or R–134a is excluded from the scope of the *Order.*

Excluded from the *Order* are blends of refrigerant chemicals that include products other than HFCs, such as

[1] *See Antidumping or Countervailing Duty Order, Finding, or Suspended Investigation; Opportunity to Request Administrative Review and Join Annual Inquiry Service List,* 88 FR 50840 (August 2, 2023); *see also Hydrofluorocarbon Blends from the People's Republic of China: Antidumping Duty Order,* 81 FR 55436 (August 19, 2016) (*Order*).

[2] *See Initiation of Antidumping and Countervailing Duty Administrative Reviews,* 88 FR 71829 (October 18, 2023) (*Initiation Notice*).

[3] *See* Zhejiang Sanmei's Letter, ''Withdrawal of Request for Administrative Review,'' dated December 4, 2023; *see also* ICool Chemical's Letter, ''Withdrawal of Request for Administrative Review,'' dated December 8, 2023.

[4] *See* Petitioner's Letter, ''Partial Withdrawal of Request for Administrative Review,'' dated January 16, 2024.

[5] *See* Memorandum, ''Notice of Intent to Rescind Review, In Part,'' dated January 16, 2024 (Intent to Rescind Memorandum).

[6] *See* Memorandum, ''Release of U.S. Customs and Border Protection Entry Data,'' dated October 25, 2023.

[7] *See* Petitioner's Letter, ''Comments Regarding CBP Data and Respondent Selection,'' dated November 1, 2023.

[8] *See Initiation Notice,* 88 FR at 71830, where Commerce noted that ''{e}xporters and producers must file a timely Separate Rate Application or Certification if they want to be considered for individual examination.'' *See also, e.g., Certain Cased Pencils from the People's Republic of China: Preliminary Results of Antidumping Duty Administrative Review; 2021–2022,* 88 FR 60636 (September 5, 2023), unchanged in *Certain Cased Pencils From the People's Republic of China: Final Results of Antidumping Duty Administrative Review; 2021–2022,* 88 FR 78721 (November 16, 2023).

[9] R–404A is sold under various trade names, including Forane® 404A, Genetron® 404A, Solkane® 404A, Klea® 404A, and Suva®404A. R–407A is sold under various trade names, including Forane® 407A, Solkane® 407A, Klea®407A, and Suva®407A. R–407C is sold under various trade names, including Forane® 407C, Genetron® 407C, Solkane® 407C, Klea® 407C and Suva® 407C. R–410A is sold under various trade names, including EcoFluor R410, Forane® 410A, Genetron® R410A and AZ–20, Solkane® 410A, Klea® 410A, Suva® 410A, and Puron®. R–507A is sold under various trade names, including Forane® 507, Solkane® 507, Klea®507, Genetron®AZ–50, and Suva®507. R–32 is sold under various trade names, including Solkane®32, Forane®32, and Klea®32. R–125 is sold under various trade names, including Solkane®125, Klea®125, Genetron®125, and Forane®125. R–143a is sold under various trade names, including Solkane®143a, Genetron®143a, and Forane®125.

blends including chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), hydrocarbons (HCs), or hydrofluoroolefins (HFOs).

Also excluded from the *Order* are patented HFC blends, including, but not limited to, ISCEON® blends, including MO99™ (R–438A), MO79 (R–422A), MO59 (R–417A), MO49Plus™ (R–437A) and MO29™ (R–4 22D), Genetron® PerformaxTM LT (R–407F), Choice® R–421A, and Choice® R–421B.

HFC blends covered by the scope of the *Order* are currently classified in the Harmonized Tariff Schedule of the United States (HTSUS) at subheadings 3827.61.0000, 3827.63.0000, 3827.64.0000, 3827.65.0000, 3827.68.0000, 3827.69.0000. Although the HTSUS subheadings are provided for convenience and customs purposes, the written description of the scope is dispositive.[10]

Rescission of Administrative Review, In Part

Pursuant to 19 CFR 351.213(d)(1), Commerce will rescind an administrative review, in whole or in part, if the party that requested the review withdraws its request within 90 days of the publication of the notice of initiation of the requested review. Because interested parties withdrew all requests for administrative review of Zhejiang Sanmei and ICool Chemical within 90 days of the date of publication of the *Initiation Notice,* Commerce is rescinding this review with respect to these companies, in accordance with 19 CFR 351.213(d)(1).

Moreover, Commerce notified all interested parties of its intent to rescind this administrative review for companies with an existing separate rate because there were no reviewable, suspended entries from these companies during the POR.[11] No interested party submitted comments. Therefore, in the absence of any suspended entries of subject merchandise from Zhejiang Yonghe Refrigerant Co., Ltd. (Zhejiang Yonghe) during the POR, we are rescinding this administrative review for Zhejiang Yonghe in accordance with 19 CFR 351.213(d)(3). However, we are not rescinding this administrative review for Daikin Fluorochemicals (China) Co., Ltd., a company that was also listed in the Intent to Rescind Memorandum, because this company subsequently lost its eligibility for a separate rate.[12]

China-Wide Entity

In accordance with Commerce's policy, the China-wide entity will not be under review unless a party specifically requests, or Commerce self-initiates, a review of the entity.[13] Because no party requested a review of the China-wide entity, the entity is not under review and the entity's rate of 216.37 percent is not subject to change.[14]

Preliminary Results of Review

Commerce finds that, because none of the remaining companies under review submitted a timely separate rate application or certification, none of these companies has established its eligibility for a separate rate. Therefore, we consider the companies listed in the appendix to be part of the China-wide entity for these preliminary results, and thus, subject to the China-wide entity rate.

Disclosure and Public Comment

Normally, Commerce discloses to interested parties the calculations performed in connection with the preliminary results within five days of any public announcement or, if there is no public announcement, within five days of the date of publication of the notice of preliminary results in the **Federal Register**, in accordance with 19 CFR 351.224(b). However, because Commerce preliminarily determined that each of the companies listed in the appendix is part of the China-wide entity, there are no calculations to disclose.

Interested parties may submit case briefs to Commerce no later than 30 days after the date of publication of this notice.[15] Rebuttal briefs, limited to issues raised in the case briefs, may be filed no later than five days after the deadline for filing case briefs.[16] Interested parties who submit case briefs or rebuttal briefs in this proceeding must submit: (1) a table of contents listing each issue; and (2) a table of authorities.[17]

As provided under 19 CFR 351.309(c)(2) and (d)(2), in prior proceedings we have encouraged interested parties to provide an executive summary of their briefs that should be limited to five pages total, including footnotes. In this review, we instead request that interested parties provide at the beginning of their briefs a public executive summary for each issue raised in their briefs.[18] Further, we request that interested parties limit their public executive summary of each issue to no more than 450 words, not including citations. We intend to use the public executive summaries as the basis of the comment summaries included in the issues and decision memorandum that will accompany the final results in this administrative review. We request that interested parties include footnotes for relevant citations in the public executive summary of each issue. Note that Commerce has amended certain of its requirements pertaining to the service of documents in 19 CFR 351.303(f).[19]

Pursuant to 19 CFR 351.310(c), interested parties who wish to request a hearing must submit a written request to the Assistant Secretary for Enforcement and Compliance, filed electronically via ACCESS. Requests should contain: (1) the party's name, address, and telephone number; (2) the number of participants; and (3) a list of issues to be discussed. Issues raised in the hearing will be limited to those raised in the respective case briefs. An electronically filed hearing request must be received successfully in its entirety by Commerce's electronic records system, ACCESS, by 5:00 p.m. Eastern Time within 30 days after the date of publication of this notice. If a request for a hearing is made, Commerce will inform parties of the scheduled date for the hearing.[20]

Assessment Rates

Pursuant to section 751(a)(2)(A) of the Act and 19 CFR 351.212(b)(1), Commerce will determine, and CBP shall assess, antidumping duties on all appropriate entries of subject merchandise covered by this review. For the companies for which Commerce is rescinding this administrative review, Commerce will instruct CBP to assess antidumping duties on all appropriate entries at a rate equal to the cash deposit of estimated antidumping duties required at the time of entry, or withdrawal from warehouse, for consumption, during the period August

[10] *See Order,* 81 FR at 55436–37.

[11] *See* Intent to Rescind Memorandum.

[12] *See Hydrofluorocarbon Blends from the People's Republic of China: Final Results of Antidumping Duty Administrative Review; 2021–2022,* 89 FR 16724, 16726 (March 8, 2024).

[13] *See Antidumping Proceedings: Announcement of Change in Department Practice for Respondent Selection in Antidumping Duty Proceedings and Conditional Review of the Nonmarket Economy Entity in NME Antidumping Duty Proceedings,* 78 FR 65963 (November 4, 2013).

[14] *See Order,* 81 FR at 55438.

[15] *See* 19 CFR 351.309(c); *see also* 19 CFR 351.303 (for general filing requirements).

[16] *See* 19 CFR 351.309(d); *see also Administrative Protective Order, Service, and Other Procedures in Antidumping and Countervailing Duty Proceedings*,88 FR 67069, 67077 (September 29, 2023) (*APO and Service Final Rule*).

[17] *See* 19 CFR 351.309(c)(2) and (d)(2).

[18] We use the term ''issue'' here to describe an argument that Commerce would normally address in a comment of the Issues and Decision Memorandum.

[19] *See APO and Service Final Rule,* 88 FR at 67069.

[20] *See* 19 CFR 351.310(d).

1, 2022, through July 31, 2023, in accordance with 19 CFR 351.212(c)(1)(i). Commerce intends to issue assessment instructions to CBP regarding these entries no earlier than 35 days after the date of publication of this notice in the **Federal Register**.

If we continue to treat the companies identified in the appendix as part of the China-wide entity in the final results, we will instruct CBP to apply an *ad valorem* assessment rate of 216.37 percent to all entries of subject merchandise during the POR which were produced and/or exported by those companies. For the China-wide entity, Commerce intends to issue assessment instructions to CBP no earlier than 35 days after the date of publication of the final results of this review in the **Federal Register**. If a timely summons is filed at the U.S. Court of International Trade, the assessment instructions will direct CBP not to liquidate relevant entries until the time for parties to file a request for a statutory injunction has expired (*i.e.,* within 90 days of publication). The final results of this review shall be the basis for the assessment of antidumping duties on entries of merchandise covered by the final results of this review and for future deposits of estimated duties, where applicable.

Cash Deposit Requirements

The following cash deposit requirements will be effective upon publication of the final results of this administrative review for shipments of the subject merchandise from China entered, or withdrawn from warehouse, for consumption on or after the publication date, as provided by sections 751(a)(2)(C) of the Act: (1) for previously investigated or reviewed Chinese and non-Chinese exporters not discussed above that have separate rates, the cash deposit rate will continue to be equal to the exporter-specific weighted-average dumping margin published of the most recently-completed segment of this proceeding; (2) for all Chinese exporters of subject merchandise that have not been found to be entitled to a separate rate, the cash deposit rate will be the rate for the China-wide entity, 216.37 percent; and (3) for all non-Chinese exporters of subject merchandise which have not received their own rate, the cash deposit rate will be the rate applicable to the Chinese exporter that supplied that non-Chinese exporter. These cash deposit requirements, when imposed, shall remain in effect until further notice.

Final Results of Review

Unless otherwise extended, Commerce intends to issue the final results of this administrative review, including the results of its analysis of issues raised by the parties in the written comments, within 120 days of publication of these preliminary results in the **Federal Register**, pursuant to section 751(a)(3)(A) of the Act and 19 CFR 351.213(h)(1).

Notification to Importers

This notice also serves as a preliminary reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in Commerce's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

Notification to Interested Parties

These preliminary results are issued and published in accordance with sections 751(a)(1)(B) and 777(i)(1) of the Act and 19 CFR 351.221(b)(4).

Dated: May 2, 2024.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, performing the non-exclusive functions and duties of the Assistant Secretary for Enforcement and Compliance.

Appendix

Companies Under Review Determined To Be Part of the China-Wide Entity

1. Changzhou Vista Chemical Co., Ltd.
2. Daikin Fluorochemicals (China) Co., Ltd.
3. Dongyang Weihua Refrigerants Co., Ltd.
4. Hanzhou Icetop Refrigeration Co., Ltd.
5. Jiangsu Sanmei Chemicals Co., Ltd.
6. Oasis Chemical Co., Limited
7. Puremann, Inc.
8. Sinochem Environmental Protection Chemicals (Taicang) Co., Ltd.
9. Superfy Industrial Limited
10. Tianjin Synergy Gases Products, Co., Ltd
11. Weitron International Refrigeration Equipment (Kunshan) Co., Ltd.
12. Weitron International Refrigeration Equipment Co., Ltd.
13. Yangfar Industry Co., Ltd.
14. Zhejiang Lantian Environmental Protection Fluoro Material Co. Ltd.
15. Zhejiang Quzhou Lianzhou Refrigerants Co., Ltd.
16. Zhejiang Zhonglan Refrigeration Technology Co., Ltd.

[FR Doc. 2024–10067 Filed 5–8–24; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–588–874]

Certain Hot-Rolled Steel Flat Products From Japan: Final Results of Antidumping Duty Administrative Review; 2021–2022

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) determines that one of the two producers/exporters of hot-rolled steel flat products (hot-rolled steel) from Japan, Nippon Steel Corporation (NSC), sold subject merchandise in the United States at prices below normal value during the period of review (POR) October 1, 2021, through September 30, 2022.

DATES: Applicable May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Jun Jack Zhao or Myrna Lobo, AD/CVD Operations, Office VII, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–1396 and (202) 482–2371, respectively.

SUPPLEMENTARY INFORMATION:

Background

On November 6, 2023, Commerce published the preliminary results of this review in the **Federal Register** and invited interested parties to comment.[1] Between December 6 and 13, 2023, Commerce received timely filed briefs and rebuttal briefs from NSC[2] and Nucor Corporation (the petitioner).[3] On February 22, 2024, we extended the deadline for the final results, in accordance with section 751(a)(3)(A) of the Tariff Act of 1930, as amended (the

[1] *See Certain Hot-Rolled Steel Flat Products from Japan: Preliminary Results and Partial Rescission of Antidumping Duty Administrative; 2021–2022,* 88 FR 76170 (November 6, 2023) (*Preliminary Results*), and accompanying Preliminary Decision Memorandum.

[2] NSC is a single entity comprised of the following companies: Nippon Steel Corporation; Nippon Steel Nisshin Co., Ltd.; and Nippon Steel Trading Corporation. *See Certain Hot-Rolled Steel Flat Products from Japan: Notice of Final Results of Antidumping Duty Changed Circumstances Review,* 84 FR 46713 (September 5, 2019).

[3] *See* NSC's Letter, ''NSC's Case Brief,'' dated December 6, 2023; *see also* Petitioner's Letter, ''Nucor's Case Brief and Request for Hearing,'' dated December 6, 2023; NSC's Letter, ''NSC's Rebuttal Brief,'' dated December 13, 2023; Petitioner's Letter, ''Nucor's Rebuttal Brief,'' dated December 13, 2023.

Act), and 19 CFR 351.213(h)(2) until May 3, 2024.[4]

For a complete summary of the events that have occurred since Commerce published the *Preliminary Results,* as well as a full discussion of the issues raised by parties for these final results, *see* the Issues and Decision Memorandum.[5] Commerce conducted this review in accordance with section 751(a) of the Act.

Scope of the Order [6]

The merchandise covered by the *Order* is certain hot-rolled steel flat products. For a complete description of the scope of the *Order, see* the Issues and Decision Memorandum.

Analysis of Comments Received

We addressed all issues raised in the case and rebuttal briefs in the Issues and Decision Memorandum, which is hereby adopted with this notice. The issues are identified in the appendix to this notice. The Issues and Decision Memorandum is a public document and is on file electronically via Enforcement and Compliance's Antidumping and Countervailing Duty Centralized Electronic Service System (ACCESS). ACCESS is available to registered users at *https://access.trade.gov.* In addition, a complete version of the Issues and Decision Memorandum can be accessed directly at *https://access.trade.gov/public/FRNoticesListLayout.aspx.*

Changes Since the Preliminary Results

Based on our review and analysis of the comments received from parties, we did not make changes to NSC's and Tokyo Steel Manufacturing Co., Ltd.'s (Tokyo Steel) preliminary results margin calculations. For a discussion of these changes, *see* the Issues and Decision Memorandum.

Final Results of Review

Commerce determines that the following weighted-average dumping margins exist for the period October 1, 2021, through September 30, 2022:

Producer/exporter	Weighted-average dumping margin (percent)
Nippon Steel Corporation/Nippon Steel Nisshin Co., Ltd./Nippon Steel Trading Corporation [7]	1.39
Tokyo Steel Manufacturing Co., Ltd.	0.00

Disclosure

Normally, Commerce discloses to interested parties the calculations performed in final results within five days of any public announcement or, if there is no public announcement, within five days of the date of publication of the notice of final results in the **Federal Register**, in accordance with 19 CFR 351.224(b). However, because Commerce did not make any change to the *Preliminary Results,* there are no calculations to disclose.

Assessment

Commerce intends to issue assessment instructions to U.S. Customs and Border Protection (CBP) no earlier than 35 days after the date of publication of the final results of this review in the **Federal Register**. If a timely summons is filed at the U.S. Court of International Trade, the assessment instructions will direct CBP not to liquidate relevant entries until the time for parties to file a request for a statutory injunction has expired (*i.e.,* within 90 days of publication).

Where the respondent reported reliable entered values, we calculated importer- (or customer-) specific *ad valorem* rates by aggregating the dumping margins calculated for all U.S. sales to each importer (or customer) and dividing this amount by the total entered value of the sales to each importer (or customer).[8] Where Commerce calculated a weighted-average dumping margin by dividing the total amount of dumping for reviewed sales to that party by the total sales quantity associated with those transactions, Commerce will direct CBP to assess importer- (or customer-) specific assessment rates based on the resulting per-unit rates.[9] Where an importer- (or customer-) specific *ad valorem* or per-unit rate is greater than *de minimis* (*i.e.,* 0.50 percent), Commerce will instruct CBP to collect the appropriate duties at the time of liquidation.[10] Where an importer- (or customer-) specific *ad valorem* or per-unit rate is zero or *de minimis,* Commerce will instruct CBP to liquidate appropriate entries without regard to antidumping duties.[11]

Consistent with Commerce's assessment practice, for entries of subject merchandise during the POR produced by NSC or Tokyo Steel for which the producer did not know that its merchandise was destined for the United States, we will instruct CBP to liquidate unreviewed entries at the all-others rate if there is no rate for the intermediate company(ies) involved in the transaction.[12]

Cash Deposit Requirements

The following cash deposit requirements will be effective for all shipments of subject merchandise entered, or withdrawn from warehouse, for consumption on or after the publication date of the final results of this administrative review, as provided for by section 751(a)(2)(C) of the Act: (1) the cash deposit rates for the companies listed in these final results will be equal

[4] *See* Memorandum, ''Extension of Deadline for Final Results of Antidumping Duty Administrative Review; 2021–2022,'' dated February 22, 2024.

[5] *See* Memorandum, ''Issues and Decision Memorandum for the Final Results of the Administrative Review of the Antidumping Duty Order on Certain Hot-Rolled Steel Flat Products from Japan; 2021–2022,'' dated concurrently with, and hereby adopted by, this notice (Issues and Decision Memorandum).

[6] *See Certain Hot-Rolled Steel Flat Products from Australia, Brazil, Japan, the Republic of Korea, the Netherlands, the Republic of Turkey, and the United Kingdom: Amended Final Affirmative Antidumping Determinations for Australia, the Republic of Korea, and the Republic of Turkey and Antidumping Duty Orders,* 81 FR 67962 (October 3, 2016) (*Order*).

[7] Commerce found in a changed circumstances review that NSC, Nippon Steel Nisshin Co., Ltd., and Nippon Steel Trading Corporation are affiliated companies that should be treated as a single entity and as the successor-in-interest to Nippon Steel & Sumitomo Metal Corporation, Nisshin Steel Co., Ltd., and Nippon Steel & Sumikin Bussan Corporation, respectively. *See Certain Hot-Rolled Steel Flat Products from Japan: Notice of Final Results of Antidumping Duty Changed Circumstances Review,* 84 FR 46713 (September 5, 2019). Because there is no information on the record of this administrative review that would lead us to revisit this determination, we are continuing to treat these companies as part of a single entity for the purposes of this administrative review.

[8] *See* 19 CFR 351.212(b)(1).

[9] *Id.*

[10] *Id.*

[11] *See* 19 CFR 351.106(c)(2).

[12] For a full discussion of this practice, *see Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties,* 68 FR 23954 (May 6, 2003).

to the weighted-average dumping margins established in the final results of this review; (2) for merchandise exported by producers or exporters not covered in this review but covered in a prior segment of this proceeding, the cash deposit rate will continue to be the company-specific rate published for the most recently completed segment in which the company was reviewed; (3) if the exporter is not a firm covered in this review or the original less-than-fair-value (LTFV) investigation, but the producer is, the cash deposit rate will be the rate established for the most recently completed segment of this proceeding for the producer of the subject merchandise; and (4) the cash deposit rate for all other producers or exporters will continue to be 5.58 percent,[13] the all-others rate established in the LTFV investigation. These cash deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice serves as a final reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this POR. Failure to comply with this requirement could result in the presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

Administrative Protective Order

This notice also serves as a reminder to parties subject to an administrative protective order (APO) of their responsibility concerning the destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3). Timely written notification of the return or destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a sanctionable violation.

Notification to Interested Parties

We are issuing and publishing these results in accordance with sections 751(a)(1) and 777(i)(1) of the Act and 19 CFR 351.213(h) and 351.221(b)(5) of Commerce's regulations.

Dated: May 3, 2024.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, performing the non-exclusive functions and duties of the Assistant Secretary for Enforcement and Compliance.

Appendix

List of Topics Discussed in the Issues and Decision Memorandum

I. Summary
II. Background
III. Scope of the *Order*
IV. Changes Since the *Preliminary Results*
V. Discussion of the Issues
Comment 1: Whether Commerce Should Deduct Section 232 Duties From U.S. Price
Comment 2: Whether Commerce Should Use NSC's Original Home Market (HM) Sales Database
Comment 3: Whether Certain NSC HM Transportation Expenses Were Misreported Based on the Sales Term
VI. Recommendation

[FR Doc. 2024–10152 Filed 5–8–24; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–489–849]

Certain Paper Shopping Bags From the Republic of Türkiye: Antidumping Duty Order

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: Based on affirmative final determinations by the U.S. Department of Commerce (Commerce) and the U.S. International Trade Commission (ITC), Commerce is issuing an antidumping duty order on certain paper shopping bags (paper shopping bags) from the Republic of Türkiye (Türkiye).

DATES: Applicable May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Luke Caruso, AD/CVD Operations, Office IV, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–2081.

SUPPLEMENTARY INFORMATION:

Background

On March 18, 2024, Commerce published in the **Federal Register** its affirmative final determination in the less-than-fair-value (LTFV) investigation of paper shopping bags from Türkiye.[1] On May 3, 2024, Commerce published in the **Federal Register** a correction of the *Final Determination*.[2] Pursuant to section 735(d) of the Tariff Act of 1930, as amended (the Act), on May 2, 2024, the ITC notified Commerce of its affirmative final determination that an industry in the United States is materially injured, within the meaning of section 735(b)(1)(A)(i) of the Act, by reason of imports of paper shopping bags from Türkiye that are sold in the United States at LTFV.[3]

Scope of the Order

The products covered by this order are paper shopping bags from Türkiye. For a complete description of the scope of this order, *see* the appendix to this notice.

Antidumping Duty Order

Based on the above-referenced affirmative final determinations, in accordance with sections 735(c)(2) and 736 of the Act, Commerce is issuing this antidumping duty order. Moreover, because the ITC determined that U.S. imports of paper shopping bags from Türkiye are materially injuring a U.S. industry, unliquidated entries of such merchandise from Türkiye, entered or withdrawn from warehouse for consumption, as described below, are subject to the assessment of antidumping duties.

Therefore, in accordance with section 736(a)(1) of the Act, Commerce will direct U.S. Customs and Border Protection (CBP) to assess, upon further instruction by Commerce, antidumping duties equal to the amount by which the normal value of the merchandise exceeds the export price or constructed export price of the merchandise, for all relevant entries of paper shopping bags from Türkiye. With the exception of entries occurring after expiration of the provisional measures period, but before publication of the ITC's final affirmative injury determination, as further described below, antidumping duties will be assessed on unliquidated U.S. entries of paper shopping bags from Türkiye entered, or withdrawn from warehouse, for consumption on or after January 3, 2024, the date of publication of the *Preliminary Determination* in this investigation in the **Federal Register**.[4]

[13] *See Certain Hot-Rolled Steel Flat Products from Japan: Final Determination of Sales at Less Than Fair Value and Final Affirmative Determination of Critical Circumstances,* 81 FR 53409 (August 12, 2016).

[1] *See Certain Paper Shopping Bags from the Republic of Turkey: Final Affirmative Determination of Sales at Less Than Fair Value,* 89 FR 19295 (March 18, 2024) (*Final Determination*).

[2] *See Certain Paper Shopping Bags from the Republic of Türkiye: Final Affirmative Determination of Sales at Less Than Fair Value; Correction,* 89 FR 36753 (May 3, 2024).

[3] *See* ITC's Letter, Investigation No. 731–TA–1626 (Final), dated May 2, 2024.

[4] *See Certain Paper Shopping Bags from the Republic of Turkey: Preliminary Affirmative Determination of Sales at Less Than Fair Value,* 89 FR 339 (January 3, 2024) (*Preliminary Determination*).

Continuation of Suspension of Liquidation

Except as noted in the ''Provisional Measures'' section of this notice below, in accordance with section 736 of the Act, Commerce will instruct CBP to continue to suspend liquidation of all relevant entries of paper shopping bags from Türkiye. These instructions suspending liquidation will remain in effect until further notice.

Commerce will also instruct CBP to require cash deposits at a rate equal to the estimated weighted-average dumping margins listed in the table below. Accordingly, effective on the date of publication in the **Federal Register** of the notice of the ITC's affirmative final injury determination, CBP will require, at the same time as importers would normally deposit estimated duties on subject merchandise, a cash deposit at the rate equal to the relevant estimated weighted-average dumping margins listed in the table below. The all-others rate applies to all producers or exporters not specifically listed.

Estimated Weighted-Average Dumping Margins

The estimated weighted-average dumping margins for this antidumping duty order are as follows:

Exporter or producer	Estimated weighted-average dumping margin (percent)
Artpack Kagit Ambalaj Anonim Sirketi	*47.56
Oztas Ambalaj Sanayi ve Ticaret A.S	*47.56
Babet Kagitsilik	*47.56
Bati Kraft Torba Ambalaj	*47.56
BFT Packaging	*47.56
Cicupack Ambalaj	*47.56
Ekopack Kagit Ambalaj	*47.56
Elhadefler A.S	*47.56
Esda Pack Ambalaj	*47.56
Haypack Ambalaj	*47.56
Jefira Global Dis	*47.56
Kahramanmaraş Kağıt Sanayi ve Ticaret Anonim Şirketi	*47.56
Multi Kraft Ambalaj	*47.56
Rad Tekstil	*47.56
Suleyman Tabak Kagitcilik	*47.56
Sunvision Tekstil	*47.56
Yildez Paper Bag Ambalaj Pazarlama	*47.56
All Others	26.32

*Rate based on the application of adverse facts available.

Provisional Measures

Section 733(d) of the Act states that suspension of liquidation pursuant to an affirmative preliminary determination may not remain in effect for more than four months, except where exporters representing a significant proportion of exports of the subject merchandise request that Commerce extend the four-month period to no more than six months.

Commerce published the *Preliminary Determination* in this investigation on January 3, 2024. Commerce did not extend the deadline for issuing its final determination in this investigation, which it published in the **Federal Register** on March 18, 2024. Therefore, the four-month period beginning on the date of publication of the *Preliminary Determination* ended on May 1, 2024.

Consequently, in accordance with section 733(d) of the Act, Commerce will instruct CBP to terminate the suspension of liquidation, and to liquidate, without regard to antidumping duties, unliquidated U.S. entries of paper shopping bags from Türkiye entered, or withdrawn from warehouse, for consumption after May 1, 2024, the final day on which the provisional measures were in effect, through the day preceding the date of publication of the ITC's affirmative final injury determination in the **Federal Register**. Suspension of liquidation and the collection of cash deposits will resume on the date of publication of the ITC's affirmative final injury determination in the **Federal Register**.

Establishment of the Annual Inquiry Service Lists

On September 20, 2021, Commerce published the final rule titled *Regulations to Improve Administration and Enforcement of Antidumping and Countervailing Duty Laws* in the **Federal Register**.[5] On September 27, 2021, Commerce published a notification titled *Scope Ruling Application; Annual Inquiry Service List; and Informational Sessions* in the **Federal Register**.[6] The *Final Rule* and *Procedural Guidance* provide that Commerce will maintain an annual inquiry service list for each order or suspended investigation, and any interested party submitting a scope ruling application or request for circumvention inquiry shall serve a copy of the application or request on the persons on the annual inquiry service list for that order, as well as any companion order covering the same merchandise from the same country of origin.[7]

In accordance with the *Procedural Guidance,* for orders published in the **Federal Register** after November 4, 2021, Commerce will create an annual inquiry service list segment in Commerce's online e-filing and document management system, Antidumping and Countervailing Duty Electronic Service System (ACCESS), available at *https://access.trade.gov,* within five business days of publication of the notice of the order. Each annual inquiry service list will be maintained in ACCESS, under each case number, and under a specific segment type

[5] *See Regulations to Improve Administration and Enforcement of Antidumping and Countervailing Duty Laws,* 86 FR 52300 (September 20, 2021) (*Final Rule*).

[6] *See Scope Ruling Application; Annual Inquiry Service List; and Informational Sessions,* 86 FR 53205 (September 27, 2021) (*Procedural Guidance*).

[7] *Id.*

called ''AISL-Annual Inquiry Service List.'' [8]

Interested parties who wish to be added to the annual inquiry service list for an order must submit an entry of appearance in the annual inquiry service list segment in ACCESS for the order within 30 days after the date of publication of the order in the **Federal Register**. For ease of administration, Commerce requests that a law firm with more than one attorney representing an interested party in an order designate a lead attorney to be included on the annual inquiry service list. Commerce will finalize the annual inquiry service list within five business days thereafter. As mentioned in the *Procedural Guidance,* the new annual inquiry service list will be in place until the following year, when the *Opportunity Notice* for the anniversary month of the order is published in the **Federal Register**.

Commerce may update an annual inquiry service list at any time, as needed, based on interested parties' amendments to their entries of appearance to remove, or otherwise modify, their list of members and representatives, or to update contact information. Changes or announcements pertaining to these procedures will be posted to the ACCESS website at *https://access.trade.gov.*

Special Instructions for Petitioners and Foreign Governments

In the *Final Rule,* Commerce stated that, ''after an initial request and placement on the annual inquiry service list, both petitioners and foreign governments will automatically be placed on the annual inquiry service list in the years that follow.'' [9] Accordingly, as stated above, the petitioners and foreign governments should submit their initial entry of appearance after publication of this notice in the **Federal Register** in order to appear in the first annual inquiry service list for those orders for which they qualify as an interested party. Pursuant to 19 CFR 351.225(n)(3), the petitioners and foreign governments will not need to resubmit their entries of appearance each year to continue to be included on the annual inquiry service list. However, the petitioners and foreign governments are responsible for making amendments to their entries of appearance during the annual update to the annual inquiry service list in accordance with the procedures described above.

Notification to Interested Parties

This notice constitutes the antidumping duty order with respect to paper shopping bags from Türkiye, pursuant to section 736(a) of the Act. Interested parties can find a list of antidumping duty orders currently in effect at *https://enforcement.trade.gov/stats/iastats1.html.*

This antidumping duty order is issued and published in accordance with section 736(a) of the Act and 19 CFR 351.211(b).

Dated: May 6, 2024.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, performing the non-exclusive functions and duties of the Assistant Secretary for Enforcement and Compliance.

Appendix

Scope of the Order

The products within the scope of the order are paper shopping bags with handles of any type, regardless of whether there is any printing, regardless of how the top edges are finished (*e.g.,* folded, serrated, or otherwise finished), regardless of color, and regardless of whether the top edges contain adhesive or other material for sealing closed. Subject paper shopping bags have a width of at least 4.5 inches and depth of at least 2.5 inches.

Paper shopping bags typically are made of kraft paper but can be made from any type of cellulose fiber, paperboard, or pressboard with a basis weight less than 300 grams per square meter (GSM).

A non-exhaustive illustrative list of the types of handles on shopping bags covered by the scope include handles made from any materials such as twisted paper, flat paper, yarn, ribbon, rope, string, or plastic, as well as die-cut handles (whether the punchout is fully removed or partially attached as a flap). Excluded from the scope are:

- Paper sacks or bags that are of a ⅙ or 1/7 barrel size (*i.e.,* 11.5–12.5 inches in width, 6.5–7.5 inches in depth, and 13.5–17.5 inches in height) with flat paper handles or die-cut handles;
- Paper sacks or bags with die-cut handles, a grams per square meter paper weight of less than 86 GSM, and a height of less than 11.5 inches; and
- Paper sacks or bags (i) with non-paper handles made wholly of woven ribbon or other similar woven fabric [1] and (ii) that are finished with folded tops or for which tied knots or t-bar aglets (made of wood, metal, or plastic) are used to secure the handles to the bags.

The above-referenced dimensions are provided for paper bags in the opened position. The height of the bag is the distance from the bottom fold edge to the top edge (*i.e.,* excluding the height of handles that extend above the top edge). The depth of the bag is the distance from the front of the bag edge to the back of the bag edge (typically measured at the bottom of the bag). The width of the bag is measured from the left to the right edges of the front and back panels (upon which the handles typically are located).

This merchandise is currently classifiable under Harmonized Tariff Schedule of the United States (HTSUS) subheadings 4819.30.0040 and 4819.40.0040. The HTSUS subheadings are provided for convenience and customs purposes only; the written description of the scope is dispositive.

[FR Doc. 2024–10253 Filed 5–8–24; 8:45 am]

BILLING CODE 3510–DS–P

[8] This segment will be combined with the ACCESS Segment Specific Information (SSI) field which will display the month in which the notice of the order or suspended investigation was published in the **Federal Register**, also known as the anniversary month. For example, for an order under case number A–000–000 that was published in the **Federal Register** in January, the relevant segment and SSI combination will appear in ACCESS as ''AISL-January Anniversary.'' Note that there will be only one annual inquiry service list segment per case number, and the anniversary month will be pre-populated in ACCESS.

[9] *See Final Rule,* 86 FR 52335.

[1] Paper sacks or bags with handles made of braided or twisted materials, such as rope or cord, do not qualify for this exclusion.

DEPARTMENT OF COMMERCE

International Trade Administration

Quarterly Update to Annual Listing of Foreign Government Subsidies on Articles of Cheese Subject to an In-Quota Rate of Duty

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

DATES: Applicable May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Samuel Brummitt, AD/CVD Operations, Office III, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Ave. NW, Washington, DC 20230, telephone: (202) 482–7851.

SUPPLEMENTARY INFORMATION: On April 19, 2024 the U.S. Department of Commerce (Commerce), pursuant to section 702(h) of the Trade Agreements Act of 1979 (as amended) (the Act), published the quarterly update to the annual listing of foreign government subsidies on articles of cheese subject to an in-quota rate of duty covering the period July 1, 2023, through September 30, 2023.[1] In the *Third Quarter 2023 Update,* we requested that any party that had information on foreign government subsidy programs that benefited articles of cheese subject to an in-quota rate of duty submit such information to Commerce.[2] We received

[1] *See Quarterly Update to Annual Listing of Foreign Government Subsidies on Articles of Cheese Subject to an In-Quota Rate of Duty,* 89 FR 28745 (April 19, 2023) (*Third Quarter 2023 Update*).

[2] *Id.*

no comments, information, or requests for consultation from any party.

Pursuant to section 702(h) of the Act, we hereby provide Commerce's update of subsidies on articles of cheese that were imported during the period October 1, 2023, through December 31, 2023. The appendix to this notice lists the country, the subsidy program or programs, and the gross and net amounts of each subsidy for which information is currently available.

Commerce will incorporate additional programs which are found to constitute subsidies, and additional information on the subsidy programs listed, as the information is developed. Commerce encourages any person having information on foreign government subsidy programs which benefit articles of cheese subject to an in-quota rate of duty to submit such information in writing through the Federal eRulemaking Portal at *https://www.regulations.gov,* Docket No. ITA–2020–0005, ''Quarterly Update to Cheese Subject to an In-Quota Rate of Duty.'' The materials in the docket will not be edited to remove identifying or contact information, and Commerce cautions against including any information in an electronic submission that the submitter does not want publicly disclosed. Attachments to electronic comments will be accepted in Microsoft Word, Excel, or Adobe PDF formats only. All comments should be addressed to the Assistant Secretary for Enforcement and Compliance, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230.

This determination and notice are in accordance with section 702(a) of the Act.

Dated: May 3, 2024.

Ryan Majerus,

Deputy Assistant Secretary for Policy and Negotiations, performing the non-exclusive functions and duties of the Assistant Secretary for Enforcement and Compliance.

Appendix

Subsidy Programs on Cheese Subject to an In-Quota Rate of Duty

Country	Program(s)	Gross[3] subsidy ($/lb)	Net[4] subsidy ($/lb)
27 European Union Member States[5]	European Union Restitution Payments	$ 0.00	$0.00
Canada	Export Assistance on Certain Types of Cheese	0.47	0.47
Norway	Indirect (Milk) Subsidy Consumer Subsidy	0.00	0.00
	Total	0.00	0.00
Switzerland	Deficiency Payments	0.00	0.00

[FR Doc. 2024–10128 Filed 5–8–24; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Agency Information Collection Activities; Submission to the Office of Management and Budget (OMB) for Review and Approval; Comment Request; Southeast Region Vessel and Gear Identification Requirements

AGENCY: National Marine Fisheries Service (NMFS), Commerce.

ACTION: Notice of information collection; request for comments.

SUMMARY: The Department of Commerce, in accordance with the Paperwork Reduction Act of 1995 (PRA), invites the general public and other Federal agencies to comment on proposed and continuing information collections, which helps us assess the impact of our information collection requirements and minimize the public's reporting burden. The purpose of this notice is to allow for 60 days of public comment preceding submission of the collection to the Office of Management and Budget (OMB).

DATES: To ensure consideration, comments regarding this proposed information collection must be received by July 8, 2024.

ADDRESSES: Interested persons are invited to submit written comments to Adrienne Thomas, NOAA PRA Officer, at *noaa.pra@noaa.gov.* Please reference OMB Control Number 0648–0358 in the subject line of your comments. All comments received are part of the public record and will generally be posted on *https://www.regulations.gov* without change. Do not submit confidential business information or otherwise sensitive or protected information.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or specific questions related to collection activities should be directed to Adam Bailey, NMFS, Southeast Regional Office, Sustainable Fisheries Division, 263 13th Avenue South, St. Petersburg, FL 33701, telephone: 727–824–5305, email: *adam.bailey@noaa.gov.*

SUPPLEMENTARY INFORMATION:

I. Abstract

NMFS proposes to extend the information collection under OMB Control Number 0648–0358 without change. The NMFS Southeast Region manages domestic fisheries in the U.S. exclusive economic zone of the Caribbean, Gulf of Mexico, and South Atlantic regions under multiple fishery management plans (FMPs). The regional fishery management councils prepared the FMPs pursuant to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). NMFS implements the FMPs through regulations located at 50 CFR part 622.

The regulations located at 50 CFR part 622 form the basis for the information collection requirements that are currently approved under OMB Control Number 0648–0358, Southeast Region Vessel and Gear Identification Requirements. NMFS has no immediate plans to change identification requirements for fishing vessels or gear in 50 CFR part 622.

Regulations at 50 CFR part 622 require that all federally permitted fishing vessels must be marked with some form of identification. A vessel's official number, under most regulations, must be displayed on the port and starboard sides of the deckhouse or hull, and on the weather deck. In addition, regulations for certain fisheries also require the display of the assigned color code for the vessel. The official number and color code identify each vessel and

[3] Defined in 19 U.S.C. 1677(5).≤

[4] Defined in 19 U.S.C. 1677(6).

[5] The 27 member states of the European Union are: Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, and Sweden.

should be visible at distance from the sea and in the air. These markings provide law enforcement personnel with a means to monitor fishing, at-sea processing, and other related activities, and to determine whether observed activities on the vessel are in accordance with those authorized for that vessel. NMFS, the United States Coast Guard, and other marine agencies use the identifying official number in monitoring compliance, issuing violations, prosecutions, and other enforcement actions. Vessels that are authorized for particular fisheries are readily identified and gear violations are more readily prosecuted, thereby enabling for more cost-effective enforcement.

In addition to vessel marking, requirements that fishing gear be marked are essential to facilitate enforcement. The ability to link fishing gear to the vessel owner is crucial to enforcement of regulations issued under the authority of the Magnuson-Stevens Act. The marking of fishing gear is also valuable in actions concerning damage, loss, and civil proceedings. The requirements imposed on U.S. fisheries in the southeast region apply to aquacultured live rock; golden crab traps; spiny lobster traps and buoys; black sea bass pots, buoys, and buoy lines; Spanish mackerel gillnet buoys; and buoy gear.

II. Method of Collection

Markings, such as numbers, are placed directly on fishing vessels and gear.

III. Data

OMB Control Number: 0648–0358.

Form Number(s): None.

Type of Review: Regular submission—extension of a current information collection.

Affected Public: Businesses or other for-profit organizations.

Estimated Number of Respondents: 10,031.

Estimated Time Per Response: Vessel marking: 75 minutes. Gear marking: aquacultured live rocks, 10 seconds each; golden crab traps, 2 minutes each; spiny lobster traps and buoys, 7 minutes each; black sea bass pots, buoys, and buoy lines, 16 minutes each; and Spanish mackerel gillnet buoys, 20 minutes each; and buoy gear, 10 minutes each.

Estimated Total Annual Burden Hours: 40,335.

Estimated Total Annual Cost to Public: $544,752 in recordkeeping and reporting costs.

Respondent's Obligation: Mandatory.

Legal Authority: Magnuson-Stevens Act, 16 U.S.C. 1801 *et seq.*

IV. Request for Comments

We are soliciting public comments to: (a) Evaluate whether the proposed information collection is necessary for the proper functions of the Department, including whether the information will have practical utility; (b) Evaluate the accuracy of our estimate of the time and cost burden for this proposed collection, including the validity of the methodology and assumptions used; (c) Evaluate ways to enhance the quality, utility, and clarity of the information to be collected; and (d) Minimize the reporting burden on those who are to respond, including the use of automated collection techniques or other forms of information technology.

Comments that you submit in response to this notice are a matter of public record. We will include or summarize each comment in our request to OMB to approve this information collection review. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment, including your personal identifying information, may be made publicly available at any time. While you may ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Sheleen Dumas,

Department PRA Clearance Officer, Office of the Under Secretary for Economic Affairs, Commerce Department.

[FR Doc. 2024–10168 Filed 5–8–24; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Agency Information Collection Activities; Submission to the Office of Management and Budget (OMB) for Review and Approval; Comment Request; Application for Appointment in the NOAA Commissioned Officer Corps

AGENCY: National Oceanic & Atmospheric Administration (NOAA), Commerce.

ACTION: Notice of information collection, request for comment.

SUMMARY: The Department of Commerce, in accordance with the Paperwork Reduction Act of 1995 (PRA), invites the general public and other Federal agencies to comment on proposed, and continuing information collections, which helps us assess the impact of our information collection requirements and minimize the public's reporting burden. The purpose of this notice is to allow for 60 days of public comment preceding submission of the collection to OMB.

DATES: To ensure consideration, comments regarding this proposed information collection must be received on or before July 8, 2024.

ADDRESSES: Interested persons are invited to submit written comments to Adrienne Thomas, NOAA PRA Officer, at *NOAA.PRA@noaa.gov.* Please reference OMB Control Number 0648–0047 in the subject line of your comments. Do not submit Confidential Business Information or otherwise sensitive or protected information.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or specific questions related to collection activities should be directed to LCDR Andrew Reynaga, Chief, NOAA Corps Recruiting Branch, (301) 713–7727, or *chief.noaacorps.recruiting@noaa.gov.*

SUPPLEMENTARY INFORMATION:

I. Abstract

This is a request for revision and extension of an existing information collection.

The NOAA Commissioned Officer Corps is the uniformed service of the National Oceanic and Atmospheric Administration (NOAA), a bureau of the United States Department of Commerce. Officers serve under Senate-confirmed appointments and Presidential commissions (33 U.S.C. chapter 17, subchapter 1, sections 853 and 854). The NOAA Corps provides a cadre of professionals trained in engineering, earth sciences, oceanography, meteorology, fisheries science, and other related disciplines who serve their country by supporting NOAA's mission of surveying the Earth's oceans, coasts, and atmosphere to ensure the economic and physical well-being of the Nation.

NOAA Corps officers operate vessels and aircraft engaged in scientific missions and serve in leadership positions throughout NOAA. Persons wishing to apply for an appointment in the NOAA Commissioned Officer Corps must complete an application package, including NOAA Form 56–42, at least three letters of recommendation, a resume, and official transcripts. A personal interview must also be conducted. Eligibility requirements include a bachelor's degree with at least 48 credit hours of science, engineering,

math, or other disciplines related to NOAA's mission, excellent health, and normal color vision with uncorrected visual acuity no worse than 20/400 in each eye (correctable to 20/20).

The revision includes updates that reflect the current status of the NOAA Corps. This includes amending the essay questions and updating the instructions to reflect a new direct-to-aviation recruitment model. NOAA Form 56–80A is a required summary of Aviation experience for those applying to become NOAA Aviators. Members of the public who wish to apply to the Direct-to-Aviation NOAA Corps program are required to complete NF 56–80A.

II. Method of Collection

Applicants must utilize the online E-recruit electronic application to complete and digitally submit the forms, including the Direct-to-Aviation Summary for NOAA Corps. An in-person interview is also required.

III. Data

OMB Control Number: 0648–0047.

Form Number(s): NOAA 56–42, NOAA 56–42A, and NOAA Form 56–80A.

Type of Review: Regular submission. Revision and extension of an existing information collection.

Affected Public: Individuals.

Estimated Number of Respondents: 300.

Estimated Time per Response: Written applications, 2 hours; interviews, 5 hours; references, 15 minutes; and Direct to Aviation Summary form, 10 minutes.

Estimated Total Annual Burden Hours: 2,425.

Estimated Total Annual Cost to Public: $21,750.

Respondent's Obligation: Required to Obtain or Retain Benefits.

Legal Authority: 33 U.S.C. chapter 17, subchapter 1, sections 853 and 854.

IV. Request for Comments

We are soliciting public comments to permit the Department/Bureau to: (a) Evaluate whether the proposed information collection is necessary for the proper functions of the Department, including whether the information will have practical utility; (b) Evaluate the accuracy of our estimate of the time and cost burden for this proposed collection, including the validity of the methodology and assumptions used; (c) Evaluate ways to enhance the quality, utility, and clarity of the information to be collected; and (d) Minimize the reporting burden on those who are to respond, including the use of automated collection techniques or other forms of information technology.

Comments that you submit in response to this notice are a matter of public record. We will include or summarize each comment in our request to OMB to approve this ICR. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you may ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so.

Sheleen Dumas,

Department PRA Clearance Officer, Office of the Under Secretary for Economic Affairs, Commerce Department.

[FR Doc. 2024–10169 Filed 5–8–24; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XD743]

Takes of Marine Mammals Incidental to Specified Activities; Taking Marine Mammals Incidental to Sitka Seaplane Base Construction

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; issuance of two incidental harassment authorizations.

SUMMARY: In accordance with the regulations implementing the Marine Mammal Protection Act (MMPA) as amended, notification is hereby given that NMFS has issued two consecutive incidental harassment authorizations (IHAs) to City and Borough of Sitka (CBS) to incidentally harass marine mammals during construction activities associated with the CBS' Sitka Seaplane Base project, in Sitka, Alaska.

DATES: The authorizations are effective from July 1, 2024 through June 30, 2025 and July 1, 2025 through June 30, 2026.

ADDRESSES: Electronic copies of the application and supporting documents, as well as a list of the references cited in this document, may be obtained online at: *https://www.fisheries.noaa.gov/action/incidental-take-authorization-city-and-borough-sitkas-seaplane-base-construction-activities.* In case of problems accessing these documents, please call the contact listed below.

FOR FURTHER INFORMATION CONTACT: Jenna Harlacher, Office of Protected Resources, NMFS, (301) 427–8401.

SUPPLEMENTARY INFORMATION:

Background

The MMPA prohibits the ''take'' of marine mammals, with certain exceptions. Sections 101(a)(5)(A) and (D) of the MMPA (16 U.S.C. 1361 *et seq.*) direct the Secretary of Commerce (as delegated to NMFS) to allow, upon request, the incidental, but not intentional, taking of small numbers of marine mammals by U.S. citizens who engage in a specified activity (other than commercial fishing) within a specified geographical region if certain findings are made and either regulations are proposed or, if the taking is limited to harassment, a notice of a proposed IHA is provided to the public for review.

Authorization for incidental takings shall be granted if NMFS finds that the taking will have a negligible impact on the species or stock(s) and will not have an unmitigable adverse impact on the availability of the species or stock(s) for taking for subsistence uses (where relevant). Further, NMFS must prescribe the permissible methods of taking and other ''means of effecting the least practicable adverse impact'' on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stocks for taking for certain subsistence uses (referred to in shorthand as ''mitigation''); and requirements pertaining to the mitigation, monitoring and reporting of the takings are set forth. The definitions of all applicable MMPA statutory terms cited above are included in the relevant sections below.

Summary of Request

On September 1, 2023, NMFS received a request from CBS for two IHAs to take marine mammals incidental to the Sitka seaplane base construction project in Sitka, Alaska, over the course of 2 years. Following NMFS' review of the application and a revised version, CBS submitted a final version on November 15, 2023. The application was deemed adequate and complete on December 1, 2023. The notice of proposed IHAs published for public comment on January 11, 2024 (89 FR 1884). For both IHAs, CBS's request is for take of seven species of marine mammals by Level B harassment and, for a subset of three of these species, Level A harassment. Neither CBS nor

NMFS expect serious injury or mortality to result from this activity and, therefore, IHAs are appropriate.

Description of Activity

CBS plans to replace the existing seaplane base in the Sitka Channel in Sitka, Alaska. The purpose of this project is to construct a new seaplane base, which would address existing capacity, safety, and condition deficiencies for critical seaplane operations, and for all seaplanes to transit the Sitka Chanel more safely. The planned location of the new seaplane base in the Sitka Channel is located on the northern shore of Japonski Island in the Sitka Sound. Over the course of 2 years spanning July 2024–June 2025 and July 2025–June 2026, CBS would use a variety of methods, including vibratory and impact pile driving, and down-the-hole (DTH) drilling to install and remove piles.

Phase I would involve the installation and removal of temporary piles, and the installation of permanent piles. During Phase I, 10 16-inch (in, 0.4 meter (m)) and 16 24-in (0.6 m) permanent steel piles would be installed. The installation and removal of 12 temporary 16-in (0.4 m) steel pipe piles would be completed to support permanent pile installation. Vibratory hammers, impact hammers, and DTH drilling would be used for the installation and removal of the piles (table 1). The installation and removal of temporary piles would be conducted using impact and vibratory hammers. All permanent piles would be initially installed with a vibratory hammer. After vibratory driving, piles would be socketed into the bedrock with DTH drilling equipment. Finally, piles would be driven the final few inches of embedment with an impact hammer.

Phase II similarly would involve the installation and removal of temporary piles, and the installation of permanent piles. During Phase II six 24-in (0.6 m) steel piles would be installed. The installation and removal of six temporary 16-in (0.4 m) steel pipe piles would be completed to support the permanent pile installation. As in Phase I, vibratory hammers, impact hammers, and DTH drilling would be used for the installation and removal of the piles (table 2). The installation and removal of temporary piles would be conducted using impact and vibratory hammers. All permanent piles would be initially installed with a vibratory hammer. After vibratory driving, piles would be socketed into the bedrock with DTH drilling equipment. Finally, piles would be driven the final few inches of embedment with an impact hammer.

A further detailed description of the planned construction project is provided in the **Federal Register** notice for the proposed IHAs (89 FR 1884, January 11, 2024). Since that time, no changes have been made to the planned activities. Therefore, a detailed description is not provided here. Please refer to that **Federal Register** notice for the description of the specified activity. Mitigation, monitoring, and reporting measures are described in detail later in this document (please see Mitigation and Monitoring and Reporting).

Comments and Responses

A notice of NMFS' proposal to issue two consecutive IHAs to CBS was published in the **Federal Register** on January 11, 2024 (89 FR 1884). That notice described, in detail, CBS' activity, the marine mammal species that may be affected by the activity, and the anticipated effects on marine mammals. During that 30-day public comment period, no comments were received.

Changes From the Proposed IHAs for Final IHAs

Changes were made between publication of the notice of proposed IHAs and this notice of final IHAs. Changes have been made to correct typographical errors and inconsistences in the high frequency shutdown zones in both the Phase I and Phase II IHAs to reflect the correct shutdown zones included in the proposed **Federal Register** notice.

Description of Marine Mammals in the Area of Specified Activities

Sections 3 and 4 of the application summarize available information regarding status and trends, distribution and habitat preferences, and behavior and life history of the potentially affected species. NMFS fully considered all of this information, and we refer the reader to these descriptions, instead of reprinting the information. Additional information regarding population trends and threats may be found in NMFS' Stock Assessment Reports (SARs; *https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments*) and more general information about these species (*e.g.,* physical and behavioral descriptions) may be found on NMFS' website (*https://www.fisheries.noaa.gov/find-species*).

Table 1 lists all species or stocks for which take is expected and authorized for this activity and summarizes information related to the population or stock, including regulatory status under the MMPA and Endangered Species Act (ESA) and potential biological removal (PBR), where known. PBR is defined by the MMPA as the maximum number of animals, not including natural mortalities, that may be removed from a marine mammal stock while allowing that stock to reach or maintain its optimum sustainable population (as described in NMFS' SARs). While no serious injury or mortality is anticipated or authorized here, PBR and annual serious injury and mortality from anthropogenic sources are included here as gross indicators of the status of the species or stocks and other threats.

Marine mammal abundance estimates presented in this document represent the total number of individuals that make up a given stock or the total number estimated within a particular study or survey area. NMFS' stock abundance estimates for most species represent the total estimate of individuals within the geographic area, if known, that comprises that stock. For some species, this geographic area may extend beyond U.S. waters. All managed stocks in this region are assessed in NMFS' U.S. Alaska Marine Mammal SARs. All values presented in table 1 are the most recent available final SAR at the time of publication of NMFS' proposed IHAs and are available online at: *https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessments.*

TABLE 1—SPECIES LIKELY IMPACTED BY THE SPECIFIED ACTIVITIES

Common name	Scientific name	Stock	ESA/ MMPA status; strategic (Y/N) [1]	Stock abundance (CV, N_{min}, most recent abundance survey) [2]	PBR	Annual M/SI [3]
Order Cetartiodactyla—Cetacea—Superfamily Mysticeti (baleen whales)						
Family Balaenopteridae (rorquals):						
Humpback Whale	*Megaptera novaeangliae*	Hawai'i	-,-,N	11,278 (0.56, 7,265, 2020).	127	27
		Mexico-North Pacific	T,D,Y	N/A (N/A, N/A, 2006)	UND	0.6
Minke Whale	*Balaenoptera acutorostrata*	Alaska	-,-,N	N/A (N/A, N/A, 2018)		0
Family Eschrichtiidae:						
Gray Whale	*Eschrichtius robustus*	Eastern North Pacific	-,-,N	26,960 (0.05, 25,849, 2016).	801	131
Superfamily Odontoceti (toothed whales, dolphins, and porpoises)						
Family Delphinidae:						
Killer whale	*Orca orcinus*	Northern Resident	-,-,N	302 (N/A, 302, 2018)	2.2	0.2
		Alaska Resident	-,-,N	1,920 (N/A, 1,920, 2019)	19	1.3
		Gulf of Alaska/Aleutian Islands/ Bering Sea Transient.	-,-,N	587 (N/A, 587, 2012)	5.9	0.8
		West Coast Transient	-,-,N	349 (N/A, 349, 2018)	3.5	0.4
Family Phocoenidae (porpoises):						
Harbor porpoise	*Phocoena phocoena*	Northern Southeast Alaska	-,-,N	1,619 (0.26, 1,250, 2019)	13	5.6
Order Carnivora—Superfamily Pinnipedia						
Family Otariidae (eared seals and sea lions):						
Steller sea lion	*Eumetopias jubatus*	Western Stock	E,D,Y	52,932 (N/A, 52,932, 2019).	318	254
		Eastern Stock	-,-,N	43,201 (N/A, 43,201, 2017).	2,592	112
Family Phocidae (earless seals):						
Harbor seal	*Phoca vituline richardii*	Sitka/Chatham	-,-,N	13,289 (N/A, 11,883, 2015).	356	77

[1] ESA status: Endangered (E), Threatened (T)/MMPA status: Depleted (D). A dash (-) indicates that the species is not listed under the ESA or designated as depleted under the MMPA. Under the MMPA, a strategic stock is one for which the level of direct human-caused mortality exceeds PBR or which is determined to be declining and likely to be listed under the ESA within the foreseeable future. Any species or stock listed under the ESA is automatically designated under the MMPA as depleted and as a strategic stock.

[2] NMFS marine mammal SARs online at: *https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-stock-assessment-reports* CV is coefficient of variation; N_{min} is the minimum estimate of stock abundance.

[3] These values, found in NMFS's SARs, represent annual levels of human-caused mortality plus serious injury from all sources combined (*e.g.,* commercial fisheries, ship strike). Annual M/SI often cannot be determined precisely and is in some cases presented as a minimum value or range.

As indicated above, all 7 species (with 12 managed stocks) in table 1 temporally and spatially co-occur with the activity to the degree that take is reasonably likely to occur. All species that could potentially occur in the action area are included in table 8 of the IHA application. While northern fur seal, Pacific white-sided dolphin, Dall's porpoise, North Pacific right whale, sperm whale, fin whale, and Cuvier's beaked whale have been documented in or near Sitka Sound and Sitka Channel, the temporal and/or spatial occurrence of these species is such that take is not expected to occur, and they are not discussed further beyond the explanation provided here. These species are all considered to be rare (no sightings in recent years) or very rare (no local knowledge of sightings within the project vicinity) within Sitka Sound or near the action area. The take of these species has not been requested nor is authorized and these species are not considered further in this document. Additionally, the Northern Sea Otter may be found in Sitka Sound. However, the Northern Sea Otter are managed by the U.S. Fish and Wildlife Service and are not considered further in this document.

A detailed description of the species likely to be affected by CBS' construction project, were provided in the **Federal Register** notice for the proposed IHAs (89 FR 1884, January 11, 2024). Since that time, we are not aware of any changes in the status of these species and stocks; therefore, detailed descriptions are not provided here. Please refer to the **Federal Register** notice for these descriptions. Please also refer to the NMFS website (*https://www.fisheries.noaa.gov/find-species*) for generalized species descriptions.

Marine Mammal Hearing

Hearing is the most important sensory modality for marine mammals underwater, and exposure to anthropogenic sound can have deleterious effects. To appropriately assess the potential effects of exposure to sound, it is necessary to understand the frequency ranges marine mammals are able to hear. Not all marine mammal species have equal hearing capabilities (*e.g.,* Richardson *et al.,* 1995; Wartzok and Ketten, 1999; Au and Hastings, 2008). To reflect this, Southall *et al.* (2007, 2019) recommended that marine mammals be divided into hearing groups based on directly measured (behavioral or auditory evoked potential techniques) or estimated hearing ranges (behavioral response data, anatomical modeling, *etc.*). Note that no direct measurements of hearing ability have been successfully completed for mysticetes (*i.e.,* low-frequency cetaceans). Subsequently, NMFS (2018) described generalized hearing ranges for these marine mammal hearing groups. Generalized hearing ranges were chosen based on the approximately 65 decibel (dB) threshold from the normalized composite audiograms, with the

exception for lower limits for low-frequency cetaceans where the lower bound was deemed to be biologically implausible and the lower bound from Southall *et al.* (2007) retained. Marine mammal hearing groups and their associated hearing ranges are provided in table 2.

TABLE 2—MARINE MAMMAL HEARING GROUPS

[NMFS, 2018]

Hearing group	Generalized hearing range *
Low-frequency (LF) cetaceans (baleen whales)	7 Hz to 35 kilohertz (kHz).
Mid-frequency (MF) cetaceans (dolphins, toothed whales, beaked whales, bottlenose whales)	150 Hz to 160 kHz.
High-frequency (HF) cetaceans (true porpoises, *Kogia,* river dolphins, Cephalorhynchid, *Lagenorhynchus cruciger* & *L. australis*).	275 Hz to 160 kHz.
Phocid pinnipeds (PW) (underwater) (true seals)	50 Hz to 86 kHz.
Otariid pinnipeds (OW) (underwater) (sea lions and fur seals)	60 Hz to 39 kHz.

* Represents the generalized hearing range for the entire group as a composite (*i.e.,* all species within the group), where individual species' hearing ranges are typically not as broad. Generalized hearing range chosen based on ~65 dB threshold from normalized composite audiogram, with the exception for lower limits for LF cetaceans (Southall *et al.* 2007) and PW pinniped (approximation).

The pinniped functional hearing group was modified from Southall *et al.* (2007) on the basis of data indicating that phocid species have consistently demonstrated an extended frequency range of hearing compared to otariids, especially in the higher frequency range (Hemilä *et al.,* 2006; Kastelein *et al.,* 2009; Reichmuth *et al.,* 2013).

For more detail concerning these groups and associated frequency ranges, please see NMFS (2018) for a review of available information.

Potential Effects of Specified Activities on Marine Mammals and Their Habitat

The effects of underwater noise from CBS' pile driving activities have the potential to result in behavioral harassment of marine mammals in the vicinity of the project area. The notice of the proposed IHAs (89 FR 1884, January 11, 2024) included a discussion of the effects of anthropogenic noise on marine mammals and the potential effects of under noise from CBS' pile driving activities on marine mammals and their habitat. Please refer to the notice of the proposed IHAs (89 FR 1884, January 11, 2024) for that information and analysis, which is not repeated here.

Estimated Take of Marine Mammals

This section provides an estimate of the number of incidental takes authorized through the IHAs, which will inform NMFS' consideration of ''small numbers,'' and the negligible impact determinations.

Harassment is the only type of take expected to result from these activities. Except with respect to certain activities not pertinent here, section 3(18) of the MMPA defines ''harassment'' as any act of pursuit, torment, or annoyance, which (i) has the potential to injure a marine mammal or marine mammal stock in the wild (Level A harassment); or (ii) has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering (Level B harassment).

Authorized takes would primarily be by Level B harassment, as vibratory or impact pile driving and DTH drilling has the potential to result in disruption of behavioral patterns for individual marine mammals. There is also some potential for auditory injury (Level A harassment) to result, primarily for harbor porpoise, harbor seals and Steller sea lions. Harbor porpoise have larger predicted auditory injury zones and due to their small size, they could enter the Level A harassment zone and remain undetected for sufficient duration to incur auditory injury. While Steller sea lion do not have large Level A harassment zones, they are frequently sighted in the project area and therefor have some potential for auditory injury. Additionally harbor seals have larger Level A harassment zones and are common in the action area, and therefore have potential for auditory injury. Auditory injury is unlikely to occur for all other species, based on the unlikelihood of the species in the action area and the smaller Level A harassment zones. The mitigation and monitoring measures are expected to minimize the severity of the taking to the extent practicable.

As described previously, no serious injury or mortality is anticipated or authorized for this activity. Below we describe how the take numbers are estimated.

For acoustic impacts, generally speaking, we estimate take by considering: (1) acoustic thresholds above which NMFS believes the best available science indicates marine mammals will be behaviorally harassed or incur some degree of permanent hearing impairment; (2) the area or volume of water that will be ensonified above these levels in a day; (3) the density or occurrence of marine mammals within these ensonified areas; and (4) the number of days of activities. We note that while these factors can contribute to a basic calculation to provide an initial prediction of potential takes, additional information that can qualitatively inform take estimates is also sometimes available (*e.g.,* previous monitoring results or average group size). Below, we describe the factors considered here in more detail and present the take estimates.

Acoustic Thresholds

NMFS recommends the use of acoustic thresholds that identify the received level of underwater sound above which exposed marine mammals would be reasonably expected to be behaviorally harassed (equated to Level B harassment) or to incur permanent threshold shift (PTS) of some degree (equated to Level A harassment).

Level B Harassment—Though significantly driven by received level, the onset of behavioral disturbance from anthropogenic noise exposure is also informed to varying degrees by other factors related to the source or exposure context (*e.g.,* frequency, predictability, duty cycle, duration of the exposure, signal-to-noise ratio, distance to the source), the environment (*e.g.,* bathymetry, other noises in the area, predators in the area), and the receiving animals (hearing, motivation, experience, demography, life stage, depth) and can be difficult to predict (*e.g.,* Southall *et al.,* 2007, 2021; Ellison *et al.,* 2012). Based on what the available science indicates and the practical need to use a threshold based on a metric that is both predictable and measurable for most activities, NMFS typically uses a generalized acoustic

threshold based on received level to estimate the onset of behavioral harassment. NMFS generally predicts that marine mammals are likely to be behaviorally harassed in a manner considered to be Level B harassment when exposed to underwater anthropogenic noise above root-mean-squared pressure received levels (RMS SPL) of 120 dB (referenced to 1 micropascal (re 1 µPa)) for continuous (*e.g.,* vibratory pile driving, drilling) and above RMS SPL 160 dB re 1 µPa for non-explosive impulsive (*e.g.,* seismic airguns) or intermittent (*e.g.,* scientific sonar) sources. Generally speaking, Level B harassment take estimates based on these behavioral harassment thresholds are expected to include any likely takes by temporary threshold shift (TTS) as, in most cases, the likelihood of TTS occurs at distances from the source less than those at which behavioral harassment is likely. TTS of a sufficient degree can manifest as behavioral harassment, as reduced hearing sensitivity and the potential reduced opportunities to detect important signals (conspecific communication, predators, prey) may result in changes in behavior patterns that would not otherwise occur.

CBS's planned activity includes the use of continuous (vibratory hammer and DTH drilling) and impulsive (DTH drilling and impact pile driving) sources, and therefore the RMS SPL thresholds of 120 and 160 dB re 1 µPa are applicable.

Level A Harassment—NMFS' Technical Guidance for Assessing the Effects of Anthropogenic Sound on Marine Mammal Hearing (Version 2.0) (Technical Guidance, 2018) identifies dual criteria to assess auditory injury (Level A harassment) to five different marine mammal groups (based on hearing sensitivity) as a result of exposure to noise from two different types of sources (impulsive or non-impulsive). CBS's planned activity includes the use of impulsive (impact pile driving and DTH drilling) and non-impulsive (vibratory hammer and DTH drilling) sources.

These thresholds are provided in the table below. The references, analysis, and methodology used in the development of the thresholds are described in NMFS' 2018 Technical Guidance, which may be accessed at: *https://www.fisheries.noaa.gov/national/marine-mammal-protection/marine-mammal-acoustic-technical-guidance.*

TABLE 3—THRESHOLDS IDENTIFYING THE ONSET OF PERMANENT THRESHOLD SHIFT

Hearing group	PTS onset acoustic thresholds * (received level)	
	Impulsive	Non-impulsive
Low-Frequency (LF) Cetaceans	*Cell 1:* $L_{pk,flat}$: 219 dB; $L_{E,LF,24h}$: 183 dB	*Cell 2:* $L_{E,LF,24h}$: 199 dB.
Mid-Frequency (MF) Cetaceans	*Cell 3:* $L_{pk,flat}$: 230 dB; $L_{E,MF,24h}$: 185 dB	*Cell 4:* $L_{E,MF,24h}$: 198 dB.
High-Frequency (HF) Cetaceans	*Cell 5:* $L_{pk,flat}$: 202 dB; $L_{E,HF,24h}$: 155 dB	*Cell 6:* $L_{E,HF,24h}$: 173 dB.
Phocid Pinnipeds (PW) (Underwater)	*Cell 7:* $L_{pk,flat}$: 218 dB; $L_{E,PW,24h}$: 185 dB	*Cell 8:* $L_{E,PW,24h}$: 201 dB.
Otariid Pinnipeds (OW) (Underwater)	*Cell 9:* $L_{pk,flat}$: 232 dB; $L_{E,OW,24h}$: 203 dB	*Cell 10:* $L_{E,OW,24h}$: 219 dB.

* Dual metric acoustic thresholds for impulsive sounds: Use whichever results in the largest isopleth for calculating PTS onset. If a non-impulsive sound has the potential of exceeding the peak sound pressure level thresholds associated with impulsive sounds, these thresholds should also be considered.

Note: Peak sound pressure (L_{pk}) has a reference value of 1 µPa, and cumulative sound exposure level (L_E) has a reference value of 1µPa^{2}s. In this table, thresholds are abbreviated to reflect American National Standards Institute standards (ANSI, 2013). However, peak sound pressure is defined by ANSI as incorporating frequency weighting, which is not the intent for this Technical Guidance. Hence, the subscript ''flat'' is being included to indicate peak sound pressure should be flat weighted or unweighted within the generalized hearing range. The subscript associated with cumulative sound exposure level thresholds indicates the designated marine mammal auditory weighting function (LF, MF, and HF cetaceans, and PW and OW pinnipeds) and that the recommended accumulation period is 24 hours. The cumulative sound exposure level thresholds could be exceeded in a multitude of ways (*i.e.,* varying exposure levels and durations, duty cycle). When possible, it is valuable for action proponents to indicate the conditions under which these acoustic thresholds will be exceeded.

Ensonified Area

Here, we describe operational and environmental parameters of the activity that are used in estimating the area ensonified above the acoustic thresholds, including source levels and transmission loss coefficient.

The sound field in the project area is the existing background noise plus additional construction noise from the project. Marine mammals are expected to be affected via sound generated by the primary components of the project (*i.e.,* impact pile driving, vibratory pile driving and removal, and DTH).

In order to calculate distances to the Level A harassment and Level B harassment thresholds for the methods and piles being used in this project, NMFS used acoustic monitoring data from other locations to develop source levels for the various pile types, sizes and methods (table 4). This analysis uses practical spreading loss, a standard assumption regarding sound propagation for similar environments, to estimate transmission of sound through water. For this analysis, the transmission loss factor of 15 (4.5 dB per doubling of distance) is used. A weighting adjustment factor of 2.5 or 2, a standard default value for vibratory pile driving and removal or impact driving and DTH respectively, were used to calculate Level A harassment areas.

NMFS recommends treating DTH systems as both impulsive and continuous, non-impulsive sound source types simultaneously. Thus, impulsive thresholds are used to evaluate Level A harassment, and continuous thresholds are used to evaluate Level B harassment. With regards to DTH mono-hammers, NMFS recommends proxy levels for Level A harassment based on available data regarding DTH systems of similar sized piles and holes (Denes *et al.,* 2019; Guan and Miner, 2020; Reyff and Heyvaert, 2019; Reyff, 2020; Heyvaert and Reyff, 2021).

TABLE 4—ESTIMATES UNDERWATER PROXY SOURCE LEVEL FOR PILE INSTALLATION AND REMOVAL

Method and pile type	Sound source at 10 meters			Source
Vibratory Hammer	dB rms			
16 in	161			NAVFAC 2015.
24 in	161			NAVFAC 2015.
DTH Drill	dB rms	dB SEL	dB peak	
16 in	167	146	172	Heyvaert and Reyff 2021, Guan and Miner 2020.
24 in	167	159	184	Heyvaert and Reyff 2021.
Impact Hammer	dB rms	dB SEL	dB peak	
16 in	185	175	200	Caltrans 2020.
24 in	190	177	203	Caltrans 2015.

Level B Harassment Zones

Transmission loss (TL) is the decrease in acoustic intensity as an acoustic pressure wave propagates out from a source. TL parameters vary with frequency, temperature, sea conditions, current, source and receiver depth, water depth, water chemistry, and bottom composition and topography. The general formula for underwater TL is:

$TL = B * \log_{10} (R_1/R_2)$,

Where:

TL = transmission loss in dB
B = transmission loss coefficient; for practical spreading equals 15
R_1 = the distance of the modeled SPL from the driven pile, and
R_2 = the distance from the driven pile of the initial measurement.

The recommended TL coefficient for most nearshore environments is the practical spreading value of 15. This value results in an expected propagation environment that would lie between spherical and cylindrical spreading loss conditions, which is the most appropriate assumption for CBS's planned underwater activities. The Level B harassment zones and approximate amount of area ensonified for the underwater activities are shown in table 5.

Level A Harassment Zones

The ensonified area associated with Level A harassment is more technically challenging to predict due to the need to account for a duration component. Therefore, NMFS developed an optional User Spreadsheet tool to accompany the Technical Guidance that can be used to relatively simply predict an isopleth distance for use in conjunction with marine mammal density or occurrence to help predict potential takes. We note that because of some of the assumptions included in the methods underlying this optional tool, we anticipate that the resulting isopleth estimates are typically going to be overestimates of some degree, which may result in an overestimate of potential take by Level A harassment. However, this optional tool offers the best way to estimate isopleth distances when more sophisticated modeling methods are not available or practical. For stationary sources such as pile installation or removal, the optional User Spreadsheet tool predicts the distance at which, if a marine mammal remained at that distance for the duration of the activity, it would be expected to incur PTS. The isopleths generated by the User Spreadsheet used the same TL coefficient as the Level B harassment zone calculations (*i.e.,* the practical spreading value of 15). Inputs used in the User Spreadsheet (*e.g.,* number of piles per day, duration and/or strikes per pile) are presented in tables 1 and 2. The maximum RMS SPL, sound exposure level (SEL), and resulting isopleths are reported in tables 4 and 5.

TABLE 5—LEVEL A AND LEVEL B HARASSMENT ISOPLETHS FOR PILE DRIVING ACTIVITIES

Activity	Level A isopleth (m)					Level B isopleth (m)
	LF	MF	HF	Phocids	Otariids	
Vibratory Pile Removal/Installation						
Phase I:						
16- in temp install	6.8	0.6	10.1	4.2	0.3	5,411.7
16-in temp removal	6.8	0.6	10.1	4.2	0.3	5,411.7
16-in perm install	6.8	0.6	10.1	4.2	0.3	5,411.7
24-in perm install	6.8	0.6	10.1	4.2	0.3	5,411.7
Phase II:						
16- in temp install	6.8	0.6	10.1	4.2	0.3	5,411.7
16-in temp removal	6.8	0.6	10.1	4.2	0.3	5,411.7
24-in perm install	6.8	0.6	10.1	4.2	0.3	5,411.7
DTH Pile Installation						
Phase I:						
16-in perm install	59	2.1	70.3	31.6	2.3	[1] 8,500
24-in perm install	568.9	20.2	677.6	304.4	22.2	[1] 8,500
Phase II:						
24-in perm install	568.9	20.2	677.6	304.4	22.2	[1] 8,500

TABLE 5—LEVEL A AND LEVEL B HARASSMENT ISOPLETHS FOR PILE DRIVING ACTIVITIES—Continued

Activity	Level A isopleth (m)					Level B isopleth (m)
	LF	MF	HF	Phocids	Otariids	
Impact Pile Installation						
Phase I:						
16-in temp install	231	8.2	275	123	9	464.2
16-in perm install	231	8.2	275	123	9	464.2
24-in perm install	313	11.1	373	168	12.2	1,000
Phase II:						
16-in temp install	231	8.2	275	123	9	464.2
24-in perm install	313	11.1	373	168	12.2	1,000

[1] The calculated Level B harassment zone is 13,594 m. However, the farthest distance that sound will transmit from the source is 8,500 m before transmission is stopped by landmasses.

Marine Mammal Occurrence

In this section we provide information about the occurrence of marine mammals, including density or other relevant information which will inform the take calculations.

Daily occurrence probability of each marine mammal species in the action area is based on consultation with previous monitoring reports, local researchers and marine professionals. Occurrence probability estimates are based on conservative density approximations for each species and factor in historic data of occurrence, seasonality, and group size in Sitka Sound and Sitka Channel. A summary of species occurrence is shown in table 6. To accurately describe species occurrence near the action area, marine mammals were described as either common (species sighted consistently during all monitoring efforts in the project vicinity, assume one to two groups per day), frequent (species sighted with some consistency during most monitoring efforts in the project vicinity, assume one group per week), or infrequent (species sighted occasionally during a few monitoring efforts in the project vicinity, assume one group per 2 weeks).

TABLE 6—ESTIMATED OCCURRENCE OF GROUP SIGHTINGS OF MARINE MAMMAL SPECIES

Species	Frequency	Average group size	Expected occurrence
Humpback whale	Frequent	3.4	1 group/week.
Minke whale [1]	Infrequent	3.5	1 group/2 weeks.
Gray whale	Infrequent	3.5	1 group/2 weeks.
Killer whale	Frequent	6.6	1 group/week.
Harbor porpoise	Infrequent	5.0	1 group/2 weeks.
Harbor seal [2]	Common	2.1	1–2 groups/day.
Steller sea lion [2]	Common	2.0	1–2 groups/day.

[1] Minke whale considered rare in Sitka Channel, but to be conservative they are treated as infrequent for take estimation as there is a small likelihood they could be in the area during the activity.
[2] Likelihood of one group/day in the Level A harassment zone and likelihood of two groups/day in the level B harassment zone.

Take Estimation

Here we describe how the information provided above is synthesized to produce a quantitative estimate of the take that is reasonably likely to occur and authorized.

For the total underwater take estimate, the daily occurrence probability for a species was multiplied by the estimated group size and by the number of days of each type of pile driving activity. Group size is based on the best available published research for these species and their presence in the action area.

Estimated take = Group size × Groups per day × Days of pile driving activity

Take by Level A harassment is anticipated for Steller sea lions and harbor seals. Although Steller sea lion Level A harassment zones are small, as previously discussed they are known to spend extended periods of time within the breakwaters in Sitka sound and in the project area. Harbor seals are also common in the project area and although their Level A harassment zones are farther from the project area, CBS has requested a maximum shutdown zone of 125 m for harbor seals and therefor there is likelihood for take by Level A harassment of harbor seals. Take by Level A harassment is also requested for harbor porpoise. We require a maximum shutdown zone for high frequency species of 300 m in this case and therefor there is likelihood for some take by Level A harassment. Even though they are not as common within the breakwaters, their Level A harassment zone extends beyond the breakwaters and they are elusive in nature. The take by Level A harassment for both pinniped species are based on a lower daily occurrence rate based on the frequency of sightings within the smaller Level A harassment zone of the breakwaters (table 6).

Additionally, for species that are large and/or infrequent (gray whale, minke whale, humpback whale, and harbor porpoise) in Sitka Sound and are unlikely to be within the breakwaters where the action will take place, take by Level B harassment is only anticipated to occur incidental to vibratory and DTH methods, given the larger Level B harassment zones which will extend beyond the breakwaters. Anticipated take by Level A harassment for harbor seal and harbor porpoise would likely occur only incidental to impact pile driving and DTH drilling, and anticipated take of Steller sea lion by Level A harassment would likely occur only incidental to DTH drilling, due to

the larger Level A harassment zones for these activities. See table 5.

TABLE 7—TAKE OF MARINE MAMMALS BY LEVEL A AND LEVEL B HARASSMENT AND PERCENT OF STOCK TO BE TAKEN

Species	Stock	Phase 1			Phase 2		
		Level A	Level B	Percent of stock	Level A	Level B	Percent of stock
Humpback whale [1]	Hawai'i	0	11	0.1	0	4*	0
	Mexico-North Pacific [2]	0	0	0	0	0	0
Gray Whale	Eastern North Pacific	0	6	0	0	*4	0
Minke Whale	Alaska	0	6	NA	0	*4	NA
Killer whale	West Coast Transients	0	3	0.9	0	1	0.3
	Gulf, Aleutian, Bering Transient	0	6	0.9	0	2	0.3
	Northern Resident	0	3	0.9	0	1	0.3
	Alaska Resident	0	18	0.9	0	6	0.3
Harbor porpoise	Northern Southeast Alaska	*5	8	0.9	*5	*5	0.7
Harbor seal	Sitka/Chatham Alaska	48	130	1.3	13	38	0.4
Steller sea lion	Eastern US	16	121	0.3	6	35	0.1
	Western US	0	3	0	0	*2	0

[1] Take estimates are weighted based on calculated percentages of population for each distinct stock, assuming animals present would follow same probability of presence in project area. Humpback whale probability by stock based on Southeast Alaska estimates from NMFS 2021 (98 percent Hawaii distinct population segment (DPS); 2 percent Mexico DPS).

[2] ESA listed Mexico humpback whales take calculation resulted in less than 0.5 takes, therefore no takes are anticipated or authorized.

* Where calculated take was less than the average group size, the take was rounded up to a group size as that is likely what would be encountered.

Mitigation

In order to issue an IHA under section 101(a)(5)(D) of the MMPA, NMFS must set forth the permissible methods of taking pursuant to the activity, and other means of effecting the least practicable impact on the species or stock and its habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance, and on the availability of the species or stock for taking for certain subsistence uses. NMFS regulations require applicants for incidental take authorizations to include information about the availability and feasibility (economic and technological) of equipment, methods, and manner of conducting the activity or other means of effecting the least practicable adverse impact upon the affected species or stocks, and their habitat (50 CFR 216.104(a)(11)).

In evaluating how mitigation may or may not be appropriate to ensure the least practicable adverse impact on species or stocks and their habitat, as well as subsistence uses where applicable, NMFS considers two primary factors:

(1) The manner in which, and the degree to which, the successful implementation of the measure(s) is expected to reduce impacts to marine mammals, marine mammal species or stocks, and their habitat, as well as subsistence uses. This considers the nature of the potential adverse impact being mitigated (likelihood, scope, range). It further considers the likelihood that the measure will be effective if implemented (probability of accomplishing the mitigating result if implemented as planned), the likelihood of effective implementation (probability implemented as planned); and

(2) The practicability of the measures for applicant implementation, which may consider such things as cost, and impact on operations.

Mitigation Measures

For each IHA, CBS must follow mitigation measures as specified below:

- Ensure that construction supervisors and crews, the monitoring team, and relevant CBS staff are trained prior to the start of all pile driving and DTH drilling activity, so that responsibilities, communication procedures, monitoring protocols, and operational procedures are clearly understood. New personnel joining during the project must be trained prior to commencing work;
- Employ Protected Species Observers (PSOs) and establish monitoring locations as described in the application and the IHA. The Holder must monitor the project area to the maximum extent possible based on the required number of PSOs, required monitoring locations, and environmental conditions. For all pile driving and removal at least one PSO must be used. The PSO will be stationed as close to the activity as possible;
- The placement of the PSOs during all pile driving and removal and DTH drilling activities will ensure that the entire shutdown zone is visible during pile installation;
- Monitoring must take place from 30 minutes prior to initiation of pile driving or DTH drilling activity (*i.e.,* pre-clearance monitoring) through 30 minutes post-completion of pile driving or DTH drilling activity;
- Pre-start clearance monitoring must be conducted during periods of visibility sufficient for the lead PSO to determine that the shutdown zones indicated in table 10 are clear of marine mammals. Pile driving and DTH drilling may commence following 30 minutes of observation when the determination is made that the shutdown zones are clear of marine mammals;
- CBS must use soft start techniques when impact pile driving. Soft start requires contractors to provide an initial set of three strikes at reduced energy, followed by a 30-second waiting period, then two subsequent reduced-energy strike sets. A soft start must be implemented at the start of each day's impact pile driving and at any time following cessation of impact pile driving for a period of 30 minutes or longer; and
- If a marine mammal is observed entering or within the shutdown zones indicated in table 10, pile driving and DTH drilling must be delayed or halted. If pile driving is delayed or halted due to the presence of a marine mammal, the activity may not commence or resume until either the animal has voluntarily exited and been visually confirmed beyond the shutdown zone (table 11) or 15 minutes have passed without re-detection of the animal.

As planned by the applicant, in water activities will take place only between civil dawn and civil dusk when PSOs can effectively monitor for the presence of marine mammals; during conditions with a Beaufort sea state of four or less. Pile driving and DTH drilling may continue for up to 30 minutes after sunset during evening civil twilight, as necessary to secure a pile for safety prior to demobilization during this time.

The length of the post-activity monitoring period may be reduced if darkness precludes visibility of the shutdown and monitoring zones.

Shutdown Zones

CBS will establish shutdown zones for all pile driving and DTH drilling activities. The purpose of a shutdown zone is generally to define an area within which shutdown of the activity would occur upon sighting of a marine mammal (or in anticipation of an animal entering the defined area). Shutdown zones would be based upon the Level A harassment isopleth for each pile size/type and driving method where applicable, as shown in table 10.

For in-water heavy machinery activities other than pile driving, if a marine mammal comes within 10 m, work will stop and vessels will reduce speed to the minimum level required to maintain steerage and safe working conditions. A 10 m shutdown zone serves to protect marine mammals from physical interactions with project vessels during pile driving and other construction activities, such as barge positioning or drilling. If an activity is delayed or halted due to the presence of a marine mammal, the activity may not commence or resume until either the animal has voluntarily exited and been visually confirmed beyond the shutdown zone indicated in table 10 or 15 minutes have passed without re-detection of the animal. Construction activities must be halted upon observation of a species for which incidental take is not authorized or a species for which incidental take has been authorized but the authorized number of takes has been met entering or within the harassment zone.

All marine mammals will be monitored in the Level B harassment zones and throughout the area as far as visual monitoring can take place. If a marine mammal enters the Level B harassment zone, construction activities including in-water work will continue and the animal's presence within the estimated harassment zone will be documented.

CBS would also establish shutdown zones for all marine mammals for which take has not been authorized or for which incidental take has been authorized but the authorized number of takes has been met. These zones are equivalent to the Level B harassment zones for each activity. If a marine mammal species not covered under this IHA enters the shutdown zone, all in-water activities will cease until the animal leaves the zone or has not been observed for at least 15 minutes, and NMFS will be notified about species and precautions taken. Pile driving will proceed if the non-IHA species is observed to leave the Level B harassment zone or if 15 minutes have passed since the last observation.

If shutdown and/or clearance procedures would result in an imminent safety concern, as determined by CBS or its designated officials, the in-water activity will be allowed to continue until the safety concern has been addressed, and the animal will be continuously monitored.

TABLE 8—SHUTDOWN AND MONITORING ZONES

Activity	Level A isopleth (m)					Level B isopleth (m)
	LF	MF	HF [2]	Phocids [1]	Otariids	
Vibratory Pile Removal/Installation						
Phase I:						
16- in temp install	10	10	20	10	10	5,415
16-in temp removal	10	10	20	10	10	5,415
16-in perm install	10	10	20	10	10	5,415
24-in perm install	10	10	20	10	10	5,415
Phase II:						
16- in temp install	10	10	20	10	10	5,415
16-in temp removal	10	10	20	10	10	5,415
24-in perm install	10	10	20	10	10	5,415
DTH Pile Installation						
Phase I:						
16-in perm install	60	10	75	35	10	8,500
24-in perm install	570	30	300	125	30	8,500
Phase II:						
24-in perm install	570	30	300	125	30	8,500
Impact Pile Installation						
Phase I:						
16-in temp install	235	10	275	125	10	465
16-in perm install	235	10	275	125	10	465
24-in perm install	315	20	300	125	20	1,000
Phase II:						
16-in temp install	235	10	275	125	10	465
24-in perm install	315	20	300	125	20	1,000

[1] Maximum shutdown for phocids is reduced to 125 m as they are a common species within the breakwaters of Sitka Sound.
[2] Maximum shutdown for high frequency species is reduced to 300 m, given the difficulty observing harbor porpoise at greater distances.

Protected Species Observers

The placement of PSOs during all construction activities (described in the Monitoring and Reporting section) would ensure that the entire shutdown zone is visible. Should environmental conditions deteriorate such that the entire shutdown zone would not be visible (*e.g.,* fog, heavy rain), pile driving would be delayed until the PSO is confident marine mammals within the shutdown zone could be detected.

PSOs would monitor the full shutdown zones and the remaining Level A harassment and the Level B harassment zones to the extent practicable. Monitoring zones provide utility for observing by establishing monitoring protocols for areas adjacent to the shutdown zones. Monitoring zones enable observers to be aware of and communicate the presence of marine mammals in the project areas outside the shutdown zones and thus prepare for a potential cessation of activity should the animal enter the shutdown zone.

Pre-Activity Monitoring

Prior to the start of daily in-water construction activity, or whenever a break in pile driving or DTH drilling of 30 minutes or longer occurs, PSOs would observe the shutdown and monitoring zones for a period of 30 minutes. The shutdown zone would be considered cleared when a marine mammal has not been observed within the zone for that 30-minute period. If a marine mammal is observed within the shutdown zones listed in table 10, pile driving activity would be delayed or halted. If work ceases for more than 30 minutes, the pre-activity monitoring of the shutdown zones would commence. A determination that the shutdown zone is clear must be made during a period of good visibility (*i.e.,* the entire shutdown zone and surrounding waters must be visible to the naked eye).

Soft-Start Procedures

Soft-start procedures provide additional protection to marine mammals by providing warning and/or giving marine mammals a chance to leave the area prior to the hammer operating at full capacity. For impact pile driving, contractors would be required to provide an initial set of three strikes from the hammer at reduced energy, followed by a 30-second waiting period, then two subsequent reduced-energy strike sets. Soft-start would be implemented at the start of each day's impact pile driving and at any time following cessation of impact pile driving for a period of 30 minutes or longer.

Based on our evaluation of the applicant's measures NMFS has determined that the mitigation measures provide the means of effecting the least practicable impact on the affected species or stocks and their habitat, paying particular attention to rookeries, mating grounds, and areas of similar significance.

Monitoring and Reporting

In order to issue an IHA for an activity, section 101(a)(5)(D) of the MMPA states that NMFS must set forth requirements pertaining to the monitoring and reporting of such taking. The MMPA implementing regulations at 50 CFR 216.104(a)(13) indicate that requests for authorizations must include the suggested means of accomplishing the necessary monitoring and reporting that will result in increased knowledge of the species and of the level of taking or impacts on populations of marine mammals that are expected to be present while conducting the activities. Effective reporting is critical both to compliance as well as ensuring that the most value is obtained from the required monitoring.

Monitoring and reporting requirements prescribed by NMFS should contribute to improved understanding of one or more of the following:

- Occurrence of marine mammal species or stocks in the area in which take is anticipated (*e.g.,* presence, abundance, distribution, density);
- Nature, scope, or context of likely marine mammal exposure to potential stressors/impacts (individual or cumulative, acute or chronic), through better understanding of: (1) action or environment (*e.g.,* source characterization, propagation, ambient noise); (2) affected species (*e.g.,* life history, dive patterns); (3) co-occurrence of marine mammal species with the activity; or (4) biological or behavioral context of exposure (*e.g.,* age, calving or feeding areas);
- Individual marine mammal responses (behavioral or physiological) to acoustic stressors (acute, chronic, or cumulative), other stressors, or cumulative impacts from multiple stressors;
- How anticipated responses to stressors impact either: (1) long-term fitness and survival of individual marine mammals; or (2) populations, species, or stocks;
- Effects on marine mammal habitat (*e.g.,* marine mammal prey species, acoustic habitat, or other important physical components of marine mammal habitat); and
- Mitigation and monitoring effectiveness.

Visual Monitoring

Marine mammal monitoring must be conducted in accordance with the conditions in this section and the IHA. Marine mammal monitoring during pile driving activities would be conducted by PSOs meeting NMFS' following requirements:

- PSOs must be independent of the activity contractor (for example, employed by a subcontractor) and have no other assigned tasks during monitoring periods;
- At least one PSO would have prior experience performing the duties of a PSO during construction activity pursuant to a NMFS-issued incidental take authorization;
- Other PSOs may substitute education (degree in biological science or related field) or training for experience; and
- Where a team of three or more PSOs is required, a lead observer or monitoring coordinator would be designated. The lead observer would be required to have prior experience working as a marine mammal observer during construction.

PSOs should have the following additional qualifications:

- Ability to conduct field observations and collect data according to assigned protocols;
- Experience or training in the field identification of marine mammals, including the identification of behaviors;
- Sufficient training, orientation, or experience with the construction operation to provide for personal safety during observations;
- Writing skills sufficient to prepare a report of observations including but not limited to the number and species of marine mammals observed; dates and times when in-water construction activities were conducted; dates, times and reason for implementation of mitigation (or why mitigation was not implemented when required); and marine mammal behavior; and
- Ability to communicate orally, by radio or in person, with project personnel to provide real-time information on marine mammals observed in the area as necessary.

- CBS must employ up to five PSOs depending on the size of the monitoring and shutdown zones. A minimum of two PSOs (including the lead PSO) must be assigned to the active pile driving location to monitor the shutdown zones and as much of the Level B harassment zones as possible.
- CBS must establish monitoring locations with the best views of monitoring zones as described in the IHA and Monitoring Plan posted on our website.
- Up to four monitors will be used at a time depending on the size of the monitoring area. PSOs would be deployed in strategic locations around the area of potential effects at all times during in-water pile driving and removal. PSOs will be positioned at

locations that provide full views of the monitoring zones and the Level A harassment Shutdown Zones. All PSOs would have access to high-quality binoculars, range finders to monitor distances, and a compass to record bearing to animals as well as radios or cells phones for maintaining contact with work crews.

- Up to four PSOs will be stationed at the following locations: the project site, Sandy Beach Day use site, O'Connell lightering float, and Whale Park.

Monitoring would be conducted 30 minutes before, during, and 30 minutes after all in water construction activities. In addition, PSOs would record all incidents of marine mammal occurrence, regardless of distance from activity, and would document any behavioral reactions in concert with distance from piles being driven or removed. Pile driving activities include the time to install or remove a single pile or series of piles, as long as the time elapsed between uses of the pile driving equipment is no more than 30 minutes.

CBS shall conduct briefings between construction supervisors and crews, PSOs, CBS staff prior to the start of all pile driving activities and when new personnel join the work. These briefings would explain responsibilities, communication procedures, marine mammal monitoring protocol, and operational procedures.

Reporting

A draft marine mammal monitoring report will be submitted to NMFS within 90 days after the completion of pile driving and removal activities for each IHA, or 60 days prior to a requested date of issuance from any future IHAs for projects at the same location, whichever comes first. The report will include an overall description of work completed, a narrative regarding marine mammal sightings, and associated PSO data sheets. Specifically, the report must include:

- Dates and times (begin and end) of all marine mammal monitoring;
- Construction activities occurring during each daily observation period, including the number and type of piles driven or removed and by what method (*i.e.,* impact, vibratory, or DTH drilling) and the total equipment duration for vibratory removal for each pile or total number of strikes for each pile (impact driving);
- PSO locations during marine mammal monitoring;
- Environmental conditions during monitoring periods (at beginning and end of PSO shift and whenever conditions change significantly), including Beaufort sea state and any other relevant weather conditions including cloud cover, fog, sun glare, and overall visibility to the horizon, and estimated observable distance;
- Upon observation of a marine mammal, the following information:
- Name of PSO who sighted the animal(s) and PSO location and activity at the time of sighting;
- Time of sighting;
- Identification of the animal(s) (*e.g.,* genus/species, lowest possible taxonomic level, or unidentifiable), PSO confidence in identification, and the composition of the group if there is a mix of species;
- Distance and bearing of each marine mammal observed relative to the pile being driven for each sightings (if pile driving was occurring at time of sighting);
- Estimated number of animals (min/max/best estimate);
- Estimated number of animals by cohort (adults, juveniles, neonates, group composition, sex class, *etc.*);
- Animal's closest point of approach and estimated time spent within the harassment zone;
- Description of any marine mammal behavioral observations (*e.g.,* observed behaviors such as feeding or traveling), including an assessment of behavioral responses thought to have resulted from the activity (*e.g.,* no response or changes in behavioral state such as ceasing feeding, changing direction, flushing, or breaching);
- Number of marine mammals detected within the harassment zones and shutdown zones; by species; and
- Detailed information about any implementation of any mitigation triggered (*e.g.,* shutdowns and delays), a description of specific actions that ensured, and resulting changes in behavior of the animal(s), if any.

If no comments are received from NMFS within 30 days, the draft reports will constitute the final reports. If comments are received, a final report addressing NMFS comments must be submitted within 30 days after receipt of comments.

Reporting Injured or Dead Marine Mammals

In the event that personnel involved in the construction activities discover an injured or dead marine mammal, the IHA-holder must immediately cease the specified activities and report the incident to the Office of Protected Resources (OPR) (*PR.ITP.MonitoringReports@noaa.gov*), NMFS and to the Alaska Regional Stranding Coordinator as soon as feasible. If the death or injury was clearly caused by the specified activity, CBS must immediately cease the specified activities until NMFS is able to review the circumstances of the incident and determine what, if any, additional measures are appropriate to ensure compliance with the terms of the IHA. The IHA-holder must not resume their activities until notified by NMFS. The report must include the following information:

- Time, date, and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
- Species identification (if known) or description of the animal(s) involved;
- Condition of the animal(s) (including carcass condition if the animal is dead);
- Observed behaviors of the animal(s), if alive;
- If available, photographs or video footage of the animal(s); and
- General circumstances under which the animal was discovered.

Negligible Impact Analysis and Determination

NMFS has defined negligible impact as an impact resulting from the specified activity that cannot be reasonably expected to, and is not reasonably likely to, adversely affect the species or stock through effects on annual rates of recruitment or survival (50 CFR 216.103). A negligible impact finding is based on the lack of likely adverse effects on annual rates of recruitment or survival (*i.e.,* population-level effects). An estimate of the number of takes alone is not enough information on which to base an impact determination. In addition to considering estimates of the number of marine mammals that might be ''taken'' through harassment, NMFS considers other factors, such as the likely nature of any impacts or responses (*e.g.,* intensity, duration), the context of any impacts or responses (*e.g.,* critical reproductive time or location, foraging impacts affecting energetics), as well as effects on habitat, and the likely effectiveness of the mitigation. We also assess the number, intensity, and context of estimated takes by evaluating this information relative to population status. Consistent with the 1989 preamble for NMFS' implementing regulations (54 FR 40338, September 29, 1989), the impacts from other past and ongoing anthropogenic activities are incorporated into this analysis via their impacts on the baseline (*e.g.,* as reflected in the regulatory status of the species, population size and growth rate where known, ongoing sources of

human-caused mortality, or ambient noise levels).

To avoid repetition, the discussion of our analysis applies to all species listed in table 3, given that the anticipated effects of this activity on these different marine mammal stocks are expected to be similar. There is little information about the nature or severity of the impacts, or the size, status, or structure of any of these species or stocks that would lead to a different analysis for this activity. In addition, because both the number and nature of the estimated takes anticipated to occur are identical in Phase I and II, the analysis below applies to both of the IHAs.

Pile driving and DTH drilling activities associated with the project, as outlined previously, have the potential to disturb or displace marine mammals. Specifically, the specified activities may result in take, in the form of Level B harassment and, for some species, Level A harassment from underwater sounds generated by pile driving and DTH drilling. Potential takes could occur if individuals are present in the ensonified zone when these activities are underway.

No serious injury or mortality would be expected, even in the absence of required mitigation measures, given the nature of the activities. Further, no take by Level A harassment is anticipated for killer whales, humpback whales, gray whales, or minke whales due to the application of planned mitigation measures, such as shutdown zones that encompass the Level A harassment zones for the species, the rarity of the species near the action area, and the small Level A harassment zones (for killer whales only). The potential for harassment would be minimized through the construction method and the implementation of the planned mitigation measures (see Mitigation section).

Take by Level A harassment is authorized for three species (harbor porpoise, Steller sea lion, and harbor seal) as the Level A harassment isopleths exceed the size of the shutdown zones for specific construction scenarios, the Level A harassment zones are large, and/or the species is frequent near the action area. Therefore, there is the possibility that an animal could enter a Level A harassment zone and remain within that zone for a duration long enough to incur PTS. Level A harassment of these species is therefore authorized. Any take by Level A harassment is expected to arise from, at most, a small degree of PTS (*i.e.,* minor degradation of hearing capabilities within regions of hearing that align most completely with the energy produced by impact pile driving such as the low-frequency region below 2 kHz), not severe hearing impairment or impairment within the ranges of greatest hearing sensitivity. Animals would need to be exposed to higher levels and/or longer duration than are expected to occur here in order to incur any more than a small degree of PTS.

Further, the amount of take authorized by Level A harassment is very low for the marine mammal stocks and species. If hearing impairment occurs, it is most likely that the affected animal would lose only a few decibels in its hearing sensitivity. Due to the small degree anticipated, any PTS potential incurred would not be expected to affect the reproductive success or survival of any individuals, much less result in adverse impacts on the species or stock.

The Level A harassment zones identified in table 7 are based upon an animal exposed to pile driving or DTH drilling of several piles per day (six piles per day for vibratory removal and installation, four piles per day of impact driving, and two piles per day of DTH drilling). Given the short duration to impact drive or vibratory install or remove, or use DTH drilling, each pile and break between pile installations (to reset equipment and move piles into place), an animal would have to remain within the area estimated to be ensonified above the Level A harassment threshold for multiple hours. This is highly unlikely given marine mammal movement patterns in the area. If an animal was exposed to accumulated sound energy, the resulting PTS would likely be small (*e.g.,* PTS onset) at lower frequencies where pile driving energy is concentrated, and unlikely to result in impacts to individual fitness, reproduction, or survival.

Additionally, some subset of the individuals that are behaviorally harassed could also simultaneously incur some small degree of TTS for a short duration of time. However, since the hearing sensitivity of individuals that incur TTS is expected to recover completely within minutes to hours, it is unlikely that the brief hearing impairment would affect the individual's long-term ability to forage and communicate with conspecifics, and would therefore not likely impact reproduction or survival of any individual marine mammal, let alone adversely affect rates of recruitment or survival of the species or stock.

The nature of the pile driving project precludes the likelihood of serious injury or mortality. For all species and stocks, take would occur within a limited, confined area (adjacent to the project site) of the stock's range. The intensity and duration of take by Level A and Level B harassment would be minimized through use of mitigation measures described herein. Further, the amount of take authorized is extremely small when compared to stock abundance.

Behavioral responses of marine mammals to pile driving, pile removals, and DTH drilling in Sitka Channel and the surrounding Sitka Sound are expected to be mild, short term, and temporary. Marine mammals within the Level B harassment zones may not show any visual cues they are disturbed by activities or they could become alert, avoid the area, leave the area, or display other mild responses that are not observable such as changes in vocalization patterns. Given that pile driving, pile removal, and DTH drilling are temporary activities and effects would cease when equipment is not operating, any harassment occurring would be temporary. Additionally, many of the species present in the region would only be present temporarily based on seasonal patterns or during transit between other habitats. These species would be exposed to even smaller periods of noise-generating activity, further decreasing the impacts.

Nearly all inland waters of southeast Alaska, including Sitka Sound, are included in the southeast Alaska humpback whale feeding Biologically Important Area (BIA) (Wild *et al.,* 2023), though humpback whale distribution in southeast Alaska varies by season and waterway (Dahlheim *et al.,* 2009). Humpback whales could be present within Sitka Sound year round, however the action area is within the breakwaters where humpback whales are not commonly found and therefore, the BIA is not expected to be affected. Therefore, the planned project is not expected to have significant adverse effects on the foraging of humpback whales.

Sitka Sound is also within a gray whale migratory corridor BIA (Wild *et al.,* 2023). Construction is expected to occur while the BIA is active during the southbound migration (November to January) and northbound migration (March to May). The Sound is also a Gray whale feeding BIA. Construction is expected to overlap with the feeding BIA (March to June). However, as noted for humpback whales, project activities will only overlap seasonally in the gray whale migratory and feeding BIAs, and the overall 2 year project (Phase I and Phase II) is expected to occur over just 40 in-water workdays, further reducing the temporal overlap with the BIAs.

Additionally, the area of the feeding BIA in which impacts of the planned project may occur is small relative to both the overall area of the BIA and the overall area of suitable gray whale habitat outside of this BIA. The area of Sitka Sound affected by this project is also small relative to the rest of the Sound, such that it allows animals within the migratory corridor to still utilize Sitka Sound without necessarily being disturbed by the construction. Specifically, all Level A harassment isopleths for gray whale are within the breakwaters where gray whales are not expected. Therefore, take of gray whales using the feeding and migratory BIAs is not expected to impact feeding or migratory behavior and, therefore, would not impact reproduction or survivorship.

As noted previously, since January 1, 2019, elevated gray whale strandings have occurred along the west coast of North America from Mexico through Alaska. The event has been declared an unusual mortality event (UME), though a cause has not yet been determined. While six takes by Level B harassment in phase I and four takes by Level B harassment in phase II of gray whale are authorized for each year this is an extremely small portion of the stock (<1 percent), and CBS will be required to implement a shutdown zone that includes the entire Level A harassment zone for low-frequency cetaceans such as gray whales.

The same regions are also a part of the Western DPS Steller sea lion ESA critical habitat. While Steller sea lions are common in the project area, there are no essential physical and biological habitat features, such as haulouts or rookeries, within the project area. The nearest haulout is approximately 25 kilometers away from the project area. Therefore, the project is not expected to have significant adverse effects on the critical habitat of Western DPS Steller sea lions. No areas of specific biological importance (*e.g.,* ESA critical habitat, other BIAs, or other areas) for any other species are known to co-occur with the project area.

In addition, it is unlikely that minor noise effects in a small, localized area of habitat would have any effect on each stock's ability to recover. In combination, we believe that these factors, as well as the available body of evidence from other similar activities, demonstrate that the potential effects of the specified activities would have only minor, short-term effects on individuals. The specified activities are not expected to impact rates of recruitment or survival and would therefore not result in population-level impacts.

In summary and as described above, the following factors primarily support our determination that the impacts resulting from this activity are not expected to adversely affect any of the species or stocks through effects on annual rates of recruitment or survival:

- No serious injury or mortality is anticipated or authorized;
- Level A harassment would be very small amounts and of low degree;
- Level A harassment takes of only harbor porpoise, Steller sea lions and harbor seals;
- For all species, the Sitka Sound and channel are a very small and peripheral part of their range;
- Anticipated takes by Level B harassment are relatively low for all stocks. Level B harassment would be primarily in the form of behavioral disturbance, resulting in avoidance of the project areas around where impact or vibratory pile driving is occurring, with some low-level TTS that may limit the detection of acoustic cues for relatively brief amounts of time in relatively confined footprints of the activities;
- Effects on species that serve as prey for marine mammals from the activities are expected to be short-term and, therefore, any associated impacts on marine mammal feeding are not expected to result in significant or long-term consequences for individuals, or to accrue to adverse impacts on their populations;
- The ensonified areas are very small relative to the overall habitat ranges of all species and stocks, and would not adversely affect ESA-designated critical habitat for any species or any areas of known biological importance;
- The lack of anticipated significant or long-term negative effects to marine mammal habitat; and
- CBS would implement mitigation measures including soft-starts and shutdown zones to minimize the numbers of marine mammals exposed to injurious levels of sound, and to ensure that take by Level A harassment is, at most, a small degree of PTS.

Based on the analysis contained herein of the likely effects of the specified activity on marine mammals and their habitat, and taking into consideration the implementation of the monitoring and mitigation measures, NMFS finds that the total marine mammal take, specific to each of the 2 consecutive years of planned activity, would have a negligible impact on all affected marine mammal species or stocks.

Small Numbers

As noted previously, only take of small numbers of marine mammals may be authorized under sections 101(a)(5)(A) and (D) of the MMPA for specified activities other than military readiness activities. The MMPA does not define small numbers and so, in practice, where estimated numbers are available, NMFS compares the number of individuals taken to the most appropriate estimation of abundance of the relevant species or stock in our determination of whether an authorization is limited to small numbers of marine mammals. When the predicted number of individuals to be taken is fewer than one-third of the species or stock abundance, the take is considered to be of small numbers. Additionally, other qualitative factors may be considered in the analysis, such as the temporal or spatial scale of the activities.

The amount of take NMFS authorized, for each of the 2 consecutive years of the activity, is below one third of the estimated stock abundance for all species (in fact, take of individuals is less than 2 percent of the abundance of the affected stocks, see table 9). This is likely a conservative estimate because we assume all takes are of different individual animals, which is likely not the case. Some individuals may return multiple times in a day, but PSOs would count them as separate takes if they cannot be individually identified.

There is no current or historical estimate of the Alaska minke whale stock, but there are known to be over 1,000 minke whales in the Gulf of Alaska (Muto *et al.,* 2018), so the 10 takes by Level B harassment over the 2 years of the project duration is small relative to estimated survey abundance, even if each take occurred to a new individual. Additionally, the range of the Alaska stock of minke whales is extensive, stretching from the Canadian Pacific coast to the Chukchi Sea, and CBS's project would only impact a small portion of this range.

Based on the analysis contained herein of the planned activity (including the mitigation and monitoring measures) and the anticipated take of marine mammals, NMFS finds that, for each of the two IHAs, small numbers of marine mammals would be taken relative to the population size of the affected species or stocks.

Unmitigable Adverse Impact Analysis and Determination

In order to issue an IHA, NMFS must find that the specified activity will not have an ''unmitigable adverse impact''

on the subsistence uses of the affected marine mammal species or stocks by Alaskan Natives. NMFS has defined ''unmitigable adverse impact'' in 50 CFR 216.103 as an impact resulting from the specified activity: (1) That is likely to reduce the availability of the species to a level insufficient for a harvest to meet subsistence needs by: (i) Causing the marine mammals to abandon or avoid hunting areas; (ii) Directly displacing subsistence users; or (iii) Placing physical barriers between the marine mammals and the subsistence hunters; and (2) That cannot be sufficiently mitigated by other measures to increase the availability of marine mammals to allow subsistence needs to be met.

Sitka Channel and other nearby areas are within the traditional territory of the Sheetʻká Kwáan. Alaska natives have traditionally harvested marine mammals in Sitka, however today a majority of the subsistence harvest is of species other than marine mammals. Alaska Department Fish and Game reported that in 2013, around 11 percent of Sitka households used subsistence-caught marine mammals (ADF&G, 2023), however this is the most recent data available and there has not been a survey since.

The project is not likely to adversely impact the availability of any marine mammal species or stocks that are commonly used for subsistence purposes or impact subsistence harvest of marine mammals in the region because:

- There is no recent recorded subsistence harvest of marine mammals in the area;
- Construction activities are temporary and localized primarily within Sitka Channel;
- Construction will not take place during the herring spawning season when subsistence species are more active;
- Mitigation measures will be implemented to minimize disturbance of marine mammals in the action area; and
- The project will not result in significant changes to availability of subsistence resources.

Based on the description of the specified activity, the measures described to minimize adverse effects on the availability of marine mammals for subsistence purposes, and the mitigation and monitoring measures; NMFS has determined that, specific to each of the 2 consecutive years of planned activity, there will not be an unmitigable adverse impact on subsistence uses from CBS's activities.

Endangered Species Act

There are two marine mammals (western DPS Steller sea lion and Mexico- North Pacific DPS humpback whale) with the potential to occur in the project area that are listed as endangered or threatened under the ESA. The NMFS Alaska Regional Office issued a Biological Opinion under section 7 of the ESA on the issuance of two IHAs to CBS under section 101(a)(5)(D) of the MMPA by the NMFS OPR. The Biological Opinion concluded that this action is not likely to jeopardize the continued existence of either DPS. In addition, the action authorized no take of the Mexico- North Pacific DPS humpback whale and is not likely to adversely affect any critical habitat.

National Environmental Policy Act

To comply with the National Environmental Policy Act of 1969 (NEPA; 42 U.S.C. 4321 *et seq.*) and NOAA Administrative Order (NAO) 216–6A, NMFS must review our action (*i.e.,* the issuance of an IHA) with respect to potential impacts on the human environment.

This action is consistent with categories of activities identified in Categorical Exclusion B4 (IHAs with no anticipated serious injury or mortality) of the Companion Manual for NAO 216–6A, which do not individually or cumulatively have the potential for significant impacts on the quality of the human environment and for which we have not identified any extraordinary circumstances that would preclude this categorical exclusion. Accordingly, NMFS has determined that the issuance of these IHAs qualifies to be categorically excluded from further NEPA review.

Authorization

NMFS has issued two consecutive IHAs to CBS for conducting Seaplane Base construction in Sitka, Alaska, starting in July 2024 for Phase I and July 2025 for Phase II, provided the previously mentioned mitigation, monitoring, and reporting requirements are incorporated. The issued IHAs can be found at: *https://www.fisheries.noaa.gov/action/incidental-take-authorization-city-and-borough-sitkas-seaplane-base-construction-activities.*

Dated: May 6, 2024.

Kimberly Damon-Randall,

Director, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2024–10145 Filed 5–8–24; 8:45 am]

BILLING CODE 3510–22–P

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Agency Information Collection Activities; Comment Request; Applicant Operational and Financial Survey

AGENCY: Corporation for National and Community Service.

ACTION: Notice of information collection; request for comment.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, the Corporation for National and Community Service (operating as AmeriCorps) is proposing to renew an information collection.

DATES: Written comments must be submitted to the individual and office listed in the **ADDRESSES** section by July 8, 2024.

ADDRESSES: You may submit comments, identified by the title of the information collection activity, by any of the following methods:

(1) Electronically through *www.regulations.gov* (preferred method)

(2) By mail sent to: AmeriCorps, Attention Alex Delaney, 250 E Street SW, Washington, DC, 20525.

(3) By hand delivery or by courier to the AmeriCorps mailroom at the mail address given in paragraph (2) above, between 9 a.m. and 4 p.m. Eastern Time, Monday through Friday, except Federal holidays.

Comments submitted in response to this notice may be made available to the public through *regulations.gov*. For this reason, please do not include in your comments information of a confidential nature, such as sensitive personal information or proprietary information. If you send an email comment, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the internet. Please note that responses to this public comment request containing any routine notice about the confidentiality of the communication will be treated as public comment that may be made available to the public, notwithstanding the inclusion of the routine notice.

FOR FURTHER INFORMATION CONTACT: Alex Delaney, 202–528–2705, or by email at *ADelaney@americorps.gov*.

SUPPLEMENTARY INFORMATION: *Title of Collection:* Applicant Operational and Financial Survey.

OMB Control Number: 3045–0102.

Type of Review: Renewal.

Respondents/Affected Public: Businesses and Organizations.

Total Estimated Number of Annual Responses: 1500.

Total Estimated Number of Annual Burden Hours: 3000.

Abstract: This information collection consists of the questions applicants answer related to operational and financial management when applying for grant funding for a new project or performance period. It is not required for grant continuation or renewal applicants. Applicants respond to the questions included in these instructions when applying for funding in certain grant competitions. AmeriCorps will use the information collection to support pre-award risk assessment of applicants for grant funding. AmeriCorps also seeks to continue using the currently approved information collection until the revised information collection is approved by OMB. The currently approved information collection is due to expire on September 30, 2024.

Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. Comments are invited on: (a) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology; and (e) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; to develop, acquire, install and utilize technology and systems for the purpose of collecting, validating and verifying information, processing and maintaining information, and disclosing and providing information; to train personnel and to be able to respond to a collection of information, to search data sources, to complete and review the collection of information; and to transmit or otherwise disclose the information. All written comments will be available for public inspection on *regulations.gov*.

Caroline B. Fernandez,

Director, Office of Monitoring.

[FR Doc. 2024–10090 Filed 5–8–24; 8:45 am]

BILLING CODE 6050–28–P

U.S. International Development Finance Corporation

Notice of Public Hearing

AGENCY: U.S. International Development Finance Corporation.

ACTION: Announcement of public hearing.

SUMMARY: The Board of Directors of U.S. International Development Finance Corporation (DFC), in accordance with the Better Utilization of Investments Leading to Development (BUILD) Act of 2018, will hold a public hearing to provide an opportunity for stakeholders to present their views. Those wishing to attend, present at, or submit a written statement to the Board prior to the public hearing must provide advance notice to the agency as detailed below.

DATES: 2:00 p.m. EST, Wednesday, June 5, 2024.

ADDRESSES: The public hearing will take place virtually. Access information will be provided at the time of attendee registration.

Registration: To attend, present at, or submit a written statement to the Board prior to the public hearing, individuals must notify DFC Acting Deputy Corporate Secretary Abigail Wade at *corporate.secretary@dfc.gov* at by 5:00 p.m. EST, Tuesday, May 28, 2024.

Notices of intent to attend or present at the public hearing must include the individual's name, title, organization, address, email address, phone number, and a concise summary of the subject matter to be presented. Oral presentations may not exceed five minutes and may be reduced proportionately, if necessary, to afford all participants an opportunity to be heard.

Written statements submitted to the Board prior to the public hearing must include the individual's name, title, organization, address, email address, and phone number. Statements must be typewritten, double-spaced, and less than ten pages in length.

Deborah Papadopoulos,

Records Management Specialist.

[FR Doc. 2024–10139 Filed 5–8–24; 8:45 am]

BILLING CODE 3210–02–P

DEPARTMENT OF DEFENSE

Department of the Air Force

Notice of Intent To Prepare an Environmental Impact Statement for the 492nd Special Operations Wing Beddown at Davis-Monthan Air Force Base, Arizona

AGENCY: Department of the Air Force, lead Agency, Department of Defense.

ACTION: Notice of Intent.

SUMMARY: The Department of the Air Force (DAF) is issuing this Notice of Intent (NOI), in accordance with the National Environmental Policy Act (NEPA), to prepare an environmental impact statement (EIS) to evaluate the potential environmental impacts associated with transformation of the 492nd Special Operations Wing (492 SOW) into an Air Force Special Operations Command (AFSOC) Power Projection Wing (PPW) at Davis-Monthan Air Force Base (AFB), Arizona. This PPW would include the 492 SOW, the 6th and 319th Special Operations Squadrons, an MC–130J squadron, activation of an Intelligence Squadron (IS) under the Air Combat Command (ACC) 361st Intelligence, Surveillance, and Reconnaissance Group (361 ISRG), and Special Tactics and Special Operations Theater Air Operations Squadrons. The beddown of the 492 SOW is planned as a replacement mission for the A–10 aircraft at Davis-Monthan as they retire. There will likely be a short-term temporary overlap of the 492 SOW mission with the A–10s until their retirement is complete.

DATES: A public scoping period will take place starting from the date of this NOI publication in the **Federal Register** and will last for 30 days. Comments will be accepted at any time during the environmental impact analysis process; however, to ensure the DAF has sufficient time to consider public scoping comments during preparation of the Draft EIS, please submit comments within the 30-day scoping period.

The DAF invites the public, stakeholders, and other interested parties to attend the public scoping meeting. The in-person scoping meeting will be held on May 30 at the Tucson Convention Center, 260 S. Church Ave., Tucson, Arizona 85701. The in-person scoping meeting will take place from 5:30 p.m. to 7:30 p.m. local time. A virtual scoping meeting is scheduled for June 4 at 5:30 p.m. local time. Information on how to attend the virtual scoping meeting is available on the project website (*www.492sow-beddown-eis.com*). The scoping meetings will

provide an opportunity for attendees to learn more about the Proposed Action and Alternative and provide an early and open process to assist the DAF in determining the scope of issues for analysis in the EIS, including identifying significant environmental issues and eliminating from further study non-significant issues. Project team members will be available to answer questions and there will also be an opportunity to provide written comments. Scoping meeting notification and scoping materials will be provided in English and Spanish.

The Notice of Availability (NOA) of the Draft EIS is anticipated in the late Fall of 2024 and the NOA for the Final EIS is anticipated in the Summer of 2025. A decision could be made no earlier than 30 days after the Final EIS.

ADDRESSES: The project website (*www.492sow-beddown-eis.com*) provides information related to the EIS, such as environmental documents, schedule, and project details, as well as a comment form. Comments may be submitted via the website comment form, emailed to *afcec.czn.nepacenter@us.af.mil,* or mailed to 492 SOW Beddown EIS, 13397 Lakefront Drive; Suite 100 Earth City, MO 63045. Members of the public who want to receive future mailings informing them of the availability of the Draft EIS and Final EIS are encouraged to submit a comment that includes their name and email or postal mailing address. For other inquiries, please contact Mr. Nick Post, NEPA Project Manager at *afcec.czn.nepacenter@us.af.mil* or 1–210–925–3516.

SUPPLEMENTARY INFORMATION: The purpose for the DAF's Proposed Action is to create co-located AFSOC and ACC units that have the resources required to optimize the DAF special operations and special warfare forces to support the National Defense Strategy (NDS) while maximizing AFSOC's capabilities as a power projection wing that provides United States Special Operations Command and combatant commands specialized airpower against the entire range of threats to the United States and our allies/partners. The need for the proposed action stems from 2023 AFSOC strategic guidance, which aligns with the 2022 NDS. The strategic guidance emphasizes that the AFSOC mission is to enable the joint force by delivering AFSOC mission capabilities across the spectrum of competition and conflict. A new IS, as a geographically separated unit under ACC's 361 ISRG, is needed to continue to provide ACC direct support to the AFSOC mission. As AFSOC aircraft relocate to Davis-Monthan AFB, Arizona, the ACC cryptologic operators, analysts, and mission support personnel that currently support those aircraft and missions would need to remain co-located. The unique capabilities of the ACC IS would be critical to the success of the 492 SOW mission. This action is needed because the global security environment has fundamentally changed. In response to the changing nature of threats to the United States, AFSOC needs to accelerate transformation to properly prepare, prevent, and prevail against any adversary in today's complex and uncertain operational environment.

The DAF has identified a Proposed Action Alternative and the No Action Alternative to be carried forward for analysis in the EIS. Under the Proposed Action, the DAF would transform the 492 SOW into an AFSOC's PPW at Davis-Monthan AFB, Arizona. This PPW would include the 492 SOW, the 6th and 319th Special Operations Squadrons, an MC–130J squadron, activation of an IS as a geographically separated unit under the ACC 361 ISRG, and Special Tactics and Special Operations Theater Air Operations Squadrons. The Proposed Action would include the construction, renovation and demolition of facilities at Davis-Monthan AFB, as necessary to support the 492 SOW beddown. AFSOC aircrews would use airspace over areas in Southern Arizona and Southern New Mexico including special use airspace. No new special use airspace would be created and there would be no modifications to existing special use airspace as part of the Proposed Action Alternative.

Under the No Action Alternative, the 492 SOW beddown would not occur at Davis-Monthan AFB and there would be no new AFSOC mission personnel or ACC IS personnel at Davis Monthan AFB.

Potential impacts may include impacts to land use, airspace management, safety, noise, hazardous materials and waste, physical resources (including soil and water resources), air quality, transportation, socioeconomics, and environmental justice as well as potential impacts to cultural and biological resources due to ground disturbing activities.

Potential permits that could be required include, but are not limited to, Section 404 of the Clean Water Act, Clean Air Act, General Construction, and a National Pollutant Discharge Elimination System permit.

Scoping and Agency Coordination: Consultation will include, but not necessarily be limited to, consultation under Section 7 of the Endangered Species Act and consultation under Section 106 of the National Historic Preservation Act, to include consultation with federally recognized Native American Tribes. The DAF will determine the scope of the analysis by soliciting comments from interested local, state, and federally elected officials and agencies, federally recognized Native American tribes, as well as interested members of the public. Comments are requested on identification of potential alternatives, information, and analyses relevant to the Proposed Action.

Tommy W. Lee,

Acting Air Force Federal Register Liaison Officer.

[FR Doc. 2024–10141 Filed 5–8–24; 8:45 am]

BILLING CODE 3911–44–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Defense Health Board; Notice of Federal Advisory Committee Meeting

AGENCY: Under Secretary of Defense for Personnel and Readiness, Department Defense (DoD).

ACTION: Notice of Federal advisory committee meeting.

SUMMARY: The DoD is publishing this notice to announce that the following Federal Advisory Committee meeting of the Defense Health Board (DHB) will take place.

DATES: Open to the public Tuesday, June 4, 2024 from 12:00 p.m. to 5:30 p.m. Eastern Daylight Time (EDT).

ADDRESSES: The meeting will be held virtually. To participate in the meeting, see the Meeting Accessibility section for instructions.

FOR FURTHER INFORMATION CONTACT: CAPT Shawn Clausen, 703–275–6060 (voice), *shawn.s.clausen.mil@health.mil* (email). Mailing address is 7700 Arlington Boulevard, Suite 5101, Falls Church, Virginia 22042. Website: *https://www.health.mil/dhb.* The most up-to-date changes to the meeting agenda can be found on the website.

SUPPLEMENTARY INFORMATION: This meeting is being held under the provisions of chapter 10 of title 5, United States Code (U.S.C.) (commonly known as the ''Federal Advisory Committee Act'' or ''FACA''), 5 U.S.C. 552b (commonly known as the ''Government in the Sunshine Act''), and 41 CFR 102–3.140 and 102–3.150.

Availability of Materials for the Meeting: Additional information,

including the agenda, is available on the DHB website, *https://www.health.mil/dhb*. A copy of the agenda or any updates to the agenda for the June 4, 2024, meeting will be available on the DHB website. Any other materials presented in the meeting may also be obtained at the meeting.

Purpose of the Meeting: The DHB provides independent advice and recommendations to maximize the safety and quality of, as well as access to, health care for DoD health care beneficiaries. The purpose of the meeting is to provide progress updates on specific tasks before the DHB. In addition, the DHB will receive information briefings on current issues related to military medicine.

Agenda: The DHB anticipates receiving updates from the DHB Public Health Subcommittee's tasking on Effective Public Health Communication Strategies with DoD personnel and the DHB Trauma and Injury Subcommittee's tasking on Prolonged Theater Care. The DHB also anticipates receiving briefings about the National Center for Disaster Medicine and Public Health and the Health of the Force Report.

Meeting Accessibility: Pursuant to 5 U.S.C. 552b and 41 CFR 102–3.140 through 102–3.165, this meeting is open to the public from 12:00 p.m. to 5:30 p.m. on June 4, 2024. The meeting will be held by videoconference/teleconference. The number of participants is limited and is on a first-come basis. All members of the public who wish to participate must register by emailing their name, rank/title, and organization/company to *dha.dhb@health.mil* or by contacting Dr. Clarice Waters at (703) 275–6003 no later than Tuesday, May 28, 2024. Once registered, participant access information will be provided.

Special Accommodations: Individuals requiring special accommodations to access the public meeting should contact Dr. Clarice Waters at (703) 275–6003 at least five (5) business days prior to the meeting so that appropriate arrangements can be made.

Written Statements: Any member of the public wishing to provide comments to the DHB related to its current taskings or mission may do so at any time in accordance with section 10(a)(3) of the FACA, 41 CFR 102–3.105(j) and 102–3.140, and the procedures described in this notice. Written statements may be submitted to the DHB's Designated Federal Officer (DFO), CAPT Clausen, at *shawn.s.clausen.mil@health.mil.* Supporting documentation may also be included, to establish the appropriate historical context and to provide any necessary background information. If the written statement is not received at least five (5) business days prior to the meeting, the DFO may choose to postpone consideration of the statement until the next open meeting. The DFO will review all timely submissions with the DHB President and ensure they are provided to members of the DHB before the meeting that is subject to this notice. After reviewing the written comments, the President and the DFO may choose to invite the submitter to orally present their issue during an open portion of this meeting or at a future meeting.

Dated: May 6, 2024.

Aaron T. Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2024–10123 Filed 5–8–24; 8:45 am]

BILLING CODE 6001–FR–P

DEPARTMENT OF DEFENSE

Department of the Navy

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

Notice of Intent To Prepare an Environmental Impact Statement for Pacific Missile Range Facility and Kōkeʻe Park Geophysical Observatory Real Estate

AGENCY: Department of the Navy (DON), Department of Defense (DoD), and National Aeronautics and Space Administration (NASA).

ACTION: Notice.

SUMMARY: Pursuant to the National Environmental Policy Act (NEPA) of 1969 and regulations implemented by the Council on Environmental Quality, the Department of the Navy (DON) and National Aeronautics and Space Administration (NASA), the DON and NASA announce their intent to prepare an Environmental Impact Statement (EIS) to evaluate the potential environmental effects associated with the continued long-term DoD use of 8,348 acres of State lands on Kauai, Hawaii for operational continuity and sustainment (in support of continued military training, testing, and facility operations) at the Pacific Missile Range Facility (PMRF), and the continued long-term NASA use of 23 acres of State lands on Kauaʻi, Hawaii in support of continued operations (including measurements of the Earth's rotation and local land motion) at Kōkeʻe Park Geophysical Observatory (KPGO).

DATES: The 40-day public scoping period begins on May 8, 2024, and extends to June 17, 2024. Comments must be postmarked or submitted electronically via the project website no later than 11:59 p.m. Hawaii Standard Time (HST) on June 17, 2024 for consideration in the Draft EIS.

Public scoping meetings are planned as follows:

- June 4, 2024, from 5:00–8:00 p.m. HST at Kauaʻi Veterans Center, 3215 Kauaʻi Veterans Memorial Highway, Līhuʻe
- June 5, 2024, from 5:00–8:00 p.m. HST at Kekaha Neighborhood Center, 8130 Elepaio Road, Kekaha
- June 6, 2024, from 5:00–8:00 p.m. HST at Sheraton Coconut Beach Resort, 650 Aleka Loop, Kapaʻa

The purpose of the scoping period is to provide the public with information related to the Proposed Action, its purpose and need, environmental resources to be analyzed in the EIS, the NEPA and HEPA process, consultation under NHPA, and public involvement opportunities. The DON and NASA are providing a web-based platform, as well as public scoping meetings for the public to learn about the Proposed Action and alternatives and to provide scoping comments. Comments must be postmarked or submitted electronically via the website no later than 11:59 p.m. HST on June 17, 2024 for consideration in the Draft EIS.

ADDRESSES: The DON and NASA invite all interested parties to submit scoping comments on the EIS or information regarding historic properties or Section 106 consulting party interest through the project website at *http://www.PMRF-KPGO-EIS.com* or by mail to: Naval Facilities Engineering Systems Command, Hawaii, Environmental OPHEV2, Attention: PMRF and KPGO RE EIS Project Manager, Ms. Kerry Wells, 400 Marshall Road, Building X–11, Pearl Harbor, HI 96860.

FOR FURTHER INFORMATION CONTACT:

DON: Commander, Navy Region Hawaii, Attn: Mr. Danny Hayes, Environmental Public Affairs Specialist, by telephone (808–473–0662) or email (*danny.r.bxhayes6.civ@us.navy.mil*).

NASA: Shari A. Miller, NASA; EIS Project Manager, by telephone (757–824–2327) or email (*Shari.A.Miller@nasa.gov*).

SUPPLEMENTARY INFORMATION:

As the proposed action involves State lands, the EIS will be a joint NEPA, Hawaii Environmental Policy Act (HEPA) (as governed by Hawaii Revised Statutes [HRS] chapter 343), and Hawaii Administrative Rules (HAR) section 11–200.1 (implementing HRS chapter 343) document; therefore, the public scoping processes will run concurrently and will jointly meet NEPA and HEPA

requirements. The DON and NASA are initiating a 40-day public scoping process to receive comments on the scope of the EIS including identification of potential alternatives and environmental concerns, information and analyses relevant to the Proposed Action, issues the public would like to see addressed in the EIS, and the project's potential to affect historic properties pursuant to section 106 of the National Historic Preservation Act (NHPA) of 1966. DON's action proponent for this proposal is Commander, Navy Region Hawaii.

The DON's purpose for the Proposed Action is to maintain long-term DoD use of 8,348 acres of State lands (including leaseholds and easement lands) on Kaua'i, Hawaii for operational continuity and sustainment of the military readiness mission. NASA's purpose for the Proposed Action is to maintain long-term use of 23 acres of State land on Kaua'i, Hawaii for continued operations of KPGO. The Proposed Action is needed because the existing real estate agreements are set to expire between 2027 and 2030. Preserving the long-term DoD and NASA use of these State lands is critical for military readiness, continuation of ongoing military training and testing, and maintaining data collection efforts of global significance. It also ensures the continued conservation management by the DON and NASA of natural and cultural resources on these lands.

For the Hawaii Department of Land and Natural Resources (DLNR), in addition to its role as the lessor of State lands, the proposed real estate action presents an opportunity for the agency to secure a revenue source to support its management of public lands and associated environmental and conservation programs. Fees from leases and easements are put into a State fund as required by law.

By ensuring continued DON and NASA operations on Kaua'i, the real estate action would also preserve local jobs and income for the residents of Kaua'i, financially contribute to the overall economic well-being of Kaua'i, and maintain continued conservation management of natural and cultural resources on State lands at no cost to the State of Hawaii.

The DON and NASA have identified two preliminary action alternatives to carry forward for analysis in the EIS, along with the No Action Alternative.

Alternative 1 (Succeeding Current Real Estate Agreements): The DON and NASA would apply to DLNR for new long-term real estate agreements in the same manner and for the same uses as the current leases and easements.

Alternative 2 (Fee Simple Acquisition of Current Real Estate Agreements for Leaseholds): The DON and NASA would pursue fee simple acquisition of 700 acres (684—DON, 16—NASA) of leaseholds, and otherwise obtain use of the remaining acreage as described in Alternative 1.

Alternative 3 (No Action Alternative): The DON and NASA would not seek any real estate agreements for the State lands on Kaua'i after expiration of the leases and easements between 2027 to 2030. The current real estate agreements for 8,348 acres with the DON and 23 acres with NASA would expire. All existing infrastructure would be removed, or abandoned in place (as determined by the existing real estate agreements), from the DON and NASA leased and easement lands.

Consistent with Council on Environmental Quality regulations and HAR section 11–200.1–24(b), the scope of the analysis for the alternatives in this EIS is proportionate to the potential for environmental impacts. The following 13 resources have a potential for impacts and are analyzed in this EIS: archaeological and historic resources, cultural practices, biological resources, land use, socioeconomics, environmental justice, water resources, utilities, public health and safety, air quality and greenhouse gases, transportation, hazardous materials and wastes, and visual resources. The EIS will analyze measures that would avoid, minimize, or mitigate environmental effects. The DON and NASA will conduct coordination, consultation, and permitting activities required by the NHPA, the Endangered Species Act, the Clean Water Act, the Coastal Zone Management Act, Hawaii Revised Statues chapter 183C and HAR chapter 13–5, HAR chapter 6E, and other laws and regulations determined to be applicable to the project.

This EIS will satisfy both Federal and State of Hawaii requirements and provide the necessary analyses to allow the DON, NASA, and DLNR to consider the environmental effects of the Proposed Action and alternatives as part of their decision-making. The DON and NASA encourages Federal, State, and local agencies, and interested persons to provide comments concerning the alternatives proposed for study and environmental issues for analysis in the EIS, as well as to identify specific environmental resources the DON and NASA should consider when developing the Draft EIS. The DON and NASA will prepare the Draft EIS and will include analyses of potential effects to the resources the DON, NASA, and the commenting public have identified. All comments received during the public scoping period will be considered during EIS preparation.

Comments must be postmarked or submitted electronically by email to *info@PMRF-KPGO-EIS.com,* and/or electronically through the EIS website at *www.PMRF-KPGO-EIS.com.* Comments must be posted by 11:59 p.m. HST on June 17, 2024.

After the scoping period, the DON and NASA will develop the Draft EIS. The DON and NASA intend to release the Draft EIS in summer of 2025, the Final EIS in spring of 2026, with a Record of Decision signed in late spring of 2026.

Dated: May 6, 2024.

Emily A. Pellegrino,

Program Analyst, Directives and Regulatory Team, National Aeronautics and Space Administration.

J.E. Koningisor,

Lieutenant Commander, Judge Advocate General's Corps, U.S. Navy, Federal Register Liaison Officer.

[FR Doc. 2024–10167 Filed 5–8–24; 8:45 am]

BILLING CODE 3810–FF–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER23–2764–004.

Applicants: Northeastern Power & Gas, LLC.

Description: Tariff Amendment: Amendment to 12 to be effective 9/25/2023.

Filed Date: 5/3/24.

Accession Number: 20240503–5171.

Comment Date: 5 p.m. ET 5/24/24.

Docket Numbers: ER24–1420–001.

Applicants: Sierra Estrella Energy Storage LLC.

Description: Tariff Amendment: Response to Deficiency Letter to be effective 3/18/2024.

Filed Date: 5/3/24.

Accession Number: 20240503–5097.

Comment Date: 5 p.m. ET 5/24/24.

Docket Numbers: ER24–1421–001.

Applicants: Superstition Energy Storage LLC.

Description: Tariff Amendment: Superstition Energy Storage LLC submits tariff filing per 35.17(b): Response to Deficiency Letter to be effective 3/18/2024.

Filed Date: 5/3/24.

Accession Number: 20240503–5098.

Comment Date: 5 p.m. ET 5/24/24.

Docket Numbers: ER24–1933–000.

Applicants: AEP Texas Inc.

Description: § 205(d) Rate Filing: AEPTX-Ray Ranch Solar 1st Amended Generation Interconnection Agreement to be effective 4/9/2024.

Filed Date: 5/2/24

Accession Number: 20240502–5150.

Comment Date: 5 p.m. ET 5/23/24.

Docket Numbers: ER24–1934–000.

Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Original NSA, Service Agreement No. 7239; AB2–135 to be effective 7/2/2024.

Filed Date: 5/2/24.

Accession Number: 20240502–5160.

Comment Date: 5 p.m. ET 5/23/24.

Docket Numbers: ER24–1935–000.

Applicants: Public Service Company of New Mexico.

Description: § 205(d) Rate Filing: 5th Revised NTUA/NOA Agreements to be effective 5/1/2024.

Filed Date: 5/2/24.

Accession Number: 20240502–5169.

Comment Date: 5 p.m. ET 5/23/24

Docket Numbers: ER24–1936–000.

Applicants: Southwest Power Pool, Inc.

Description: § 205(d) Rate Filing: Tariff Clean-Up Filing Effective 20240604 to be effective 6/4/2024.

Filed Date: 5/3/24.

Accession Number: 20240503–5058.

Comment Date: 5 p.m. ET 5/24/24.

Docket Numbers: ER24–1937–000.

Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Original NSA, Service Agreement No. 7240; AC2–061 to be effective 7/3/2024.

Filed Date: 5/3/24

Accession Number: 20240503–5079

Comment Date: 5 p.m. ET 5/24/24.

Docket Numbers: ER24–1938–000.

Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Amendment to IISA No. 5885 & ICSA No. 6969, AF1–123_AF1–124_AF1–125 to be effective 7/3/2024.

Filed Date: 5/3/24.

Accession Number: 20240503–5088.

Comment Date: 5 p.m. ET 5/24/24.

Docket Numbers: ER24–1939–000.

Applicants: Midcontinent Independent System Operator, Inc.

Description: § 205(d) Rate Filing: 2024–05–03_True Up of Module B 29.2 to be effective 7/11/2025.

Filed Date: 5/3/24.

Accession Number: 20240503–5101.

Comment Date: 5 p.m. ET 5/24/24

Docket Numbers: ER24–1940–000.

Applicants: Public Service Company of Colorado.

Description: § 205(d) Rate Filing: 2024–05–03 TSGT—COM—Boone-Huckleberry—733 to be effective 7/3/2024.

Filed Date: 5/3/24.

Accession Number: 20240503–5129.

Comment Date: 5 p.m. ET 5/24/24

Docket Numbers: ER24–1941–000.

Applicants: Liberty County Solar Project, LLC.

Description: Baseline eTariff Filing: Application for Market Based Rate Authority to be effective 5/4/2024.

Filed Date: 5/3/24.

Accession Number: 20240503–5139.

Comment Date: 5 p.m. ET 5/24/24.

Docket Numbers: ER24–1942–000.

Applicants: PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: Ministerial Clean-Up Filing for Tariff, Schedule 12-Appx, Appx A & Appx C to be effective 1/1/2024.

Filed Date: 5/3/24.

Accession Number: 20240503–5144.

Comment Date: 5 p.m. ET 5/24/24.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

Any person desiring to intervene, to protest, or to answer a complaint in any of the above proceedings must file in accordance with Rules 211, 214, or 206 of the Commission's Regulations (18 CFR 385.211, 385.214, or 385.206) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

The Commission's Office of Public Participation (OPP) supports meaningful public engagement and participation in Commission proceedings. OPP can help members of the public, including landowners, environmental justice communities, Tribal members and others, access publicly available information and navigate Commission processes. For public inquiries and assistance with making filings such as interventions, comments, or requests for rehearing, the public is encouraged to contact OPP at (202) 502–6595 or *OPP@ferc.gov.*

Dated: May 3, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024–10171 Filed 5–8–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP24–756–000.

Applicants: Sabine Pipe Line LLC.

Description: § 4(d) Rate Filing: Normal filing 2024—7.25 and 7.26 to be effective 5/3/2024.

Filed Date: 5/2/24.

Accession Number: 20240502–5167.

Comment Date: 5 p.m. ET 5/13/24

Any person desiring to intervene, to protest, or to answer a complaint in any of the above proceedings must file in accordance with Rules 211, 214, or 206 of the Commission's Regulations (18 CFR 385.211, 385.214, or 385.206) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

Filings in Existing Proceedings

Docket Numbers: RP12–609–000.

Applicants: Texas Gas Transmission, LLC.

Description: Report Filing: 2023 Operational Purchases and Sales Report Filing to be effective N/A.

Filed Date: 5/1/24.

Accession Number: 20240501–5142.

Comment Date: 5 p.m. ET 5/13/24.

Docket Numbers: RP13–212–000.

Applicants: Boardwalk Storage Company, LLC.

Description: Report Filing: 2023 Operational Purchases and Sales Report Filing to be effective N/A.

Filed Date: 5/1/24.

Accession Number: 20240501–5135.

Comment Date: 5 p.m. ET 5/13/24.

Any person desiring to protest in any the above proceedings must file in accordance with Rule 211 of the Commission's Regulations (18 CFR 385.211) on or before 5:00 p.m. Eastern time on the specified comment date.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

The Commission's Office of Public Participation (OPP) supports meaningful public engagement and participation in Commission proceedings. OPP can help members of the public, including landowners, environmental justice communities, Tribal members and others, access publicly available information and navigate Commission processes. For public inquiries and assistance with making filings such as interventions, comments, or requests for rehearing, the public is encouraged to contact OPP at (202) 502–6595 or *OPP@ferc.gov.*

Dated: May 3, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024–10170 Filed 5–8–24; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL 11953–01–OA]

Extension of Deadline for Nominations to Historically Black Colleges and Universities and Minority Serving Institutions Advisory Council

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of extension of deadline.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is extending the deadline for nominations for the Historically Black Colleges and Universities and Minority Serving Institutions Advisory Council pursuant to the authority of the Federal Advisory Committee Act (FACA), as amended. The Historically Black Colleges and Universities and Minority Serving Institutions Advisory Council (HBCU–MSI AC) is a Federal advisory committee chartered under the Federal Advisory Committee Act. The HBCU–MSI AC was created in 2023 by the United States Environmental Protection Agency's Office of Public Engagement and Environmental Education at the direction of the Administrator of EPA. Implementing authority was delegated to the Administrator of EPA. The HBCU–MSI AC provides independent advice and recommendations to the Administrator of the Environmental Protection Agency (EPA) on how to leverage Historically Black Colleges and Universities and Minority Serving Institutions to help diversify the agency's workforce and nurture the next generation of environmental leaders and ensure that these vital institutions of higher learning have the resources and support to continue to thrive for generations to come. MSIs are institutions of higher education that serve minority populations and include HBCUs, Hispanic-Serving Institutions (HSIs), Tribal Colleges and Universities (TCUs), and Asian American and Pacific Islander Serving Institutions (AAPISIs).

DATES: EPA originally posted a solicitation for applications to the HBCU–MSI AC on March 25, 2024, (89 FR 20651) with an original deadline of May 8, 2024. EPA has determined that an extension of the original deadline is warranted. EPA will consider applications received by June 22, 2024, for potential selection to the inaugural HBCU–MSI AC. Applications received after this date may be considered by EPA as appropriate and when vacancies become available. If you have already submitted an application, EPA will consider your application and there is no need to re-apply.

ADDRESSES: Individuals who are interested in being considered for the HBCU–MSI AC must submit their contact information, a resume or CV and statement of interest electronically via email to Pradnya Bhandari at *HBCU-MSI.AC@epa.gov,* with the subject line HBCU–MSI AC, COMMITTEE APPLICATION PACKAGE 2024 for (Name of Nominee).

FOR FURTHER INFORMATION CONTACT: Pradnya Bhandari, Designated Federal Officer, Office of Public Engagement and Environmental Education, *HBCU-MSI.AC@epa.gov,* telephone 919–937–1989.

SUPPLEMENTARY INFORMATION: Please note that this notice is to extend the initial deadline for applications to the HBCU–MSI AC. The original notice was published on March 25, 2024 (89 FR 20651), and stated that the original deadline to receive applications was May 8, 2024. EPA has determined that an extension to this deadline is warranted. Accordingly, EPA will consider all applications received by June 24, 2024, for potential selection to the inaugural HBCU–MSI AC. Applications received after this date may be considered by MBDA as appropriate and when vacancies become available. If you have already submitted an application, EPA will consider your application and there is no need to re-apply.

The Historically Black Colleges and Universities and Minority Serving Institutions Advisory Council (HBCU–MSI AC) is a federal advisory committee chartered under the Federal Advisory Committee Act, Public Law 92–463. The HBCU–MSI AC was created in 2023 by the United States Environmental Protection Agency's Office of Public Engagement and Environmental Education at the direction of the Administrator of EPA. Implementing authority was delegated to the Administrator of EPA. The HBCU–MSI AC provides independent advice and recommendations to the Administrator of the Environmental Protection Agency (EPA) on how to leverage Historically Black Colleges and Universities and Minority Serving Institutions to help diversify the agency's workforce and nurture the next generation of environmental leaders and ensure that these vital institutions of higher learning have the resources and support to continue to thrive for generations to come. MSIs are institutions of higher education that serve minority populations and include HBCUs, Hispanic-Serving Institutions (HSIs), Tribal Colleges and Universities (TCUs), and Asian American and Pacific Islander Serving Institutions (AAPISIs).

The HBCU–MSI AC is part of a comprehensive effort to advance equity in economic and educational opportunities for all Americans while protecting human health and the environment. Members are appointed by the EPA Administrator for a two-year term. The HBCU–MSI AC expects to meet approximately two to three times a year for in-person, virtual or hybrid meetings, subject to the availability of appropriations. Members serve on the committee in a voluntary capacity. Although we are unable to offer compensation or an honorarium, members may receive travel and per diem allowances, according to applicable Federal travel regulations and the agency's budget. To learn more about HBCU–MSI AC, please visit *https://www.epa.gov/faca/historically-black-colleges-and-universities-and-minority-serving-institutions-advisory.*

The EPA is seeking nominations from a variety of sectors including but not limited to representatives from business and industry, academia, non-governmental organizations, and local, county, and Tribal governments that have experience working at or in partnership with HBCUs and/or MSIs. According to the mandates of FACA, committees are required to support diversity across a broad range of constituencies, sectors, and groups.

In accordance with Executive Order 14035 (June 25, 2021) and consistent with law, EPA values and welcomes opportunities to increase diversity, equity, inclusion, and accessibility on its Federal advisory committees. EPA's Federal advisory committees strive to have a workforce that reflects the diversity of the American people.

The following criteria will be used to evaluate applicants:

- The HBCU–MSI AC will be composed of approximately 15–20 members who will generally serve as Representative members of non-federal interests appointed by the Administrator of EPA.
- Members must have a strong affiliation with HBCUs and/or MSIs or the communities represented and served by HBCUs and/or MSIs, including through education, work, or partnerships.
- Members must demonstrate a knowledge of the student continuum from college to career, preferably through related experience with HBCUs and/or MSIs. In selecting members, EPA will consider candidates from business and industry, academic institutions, State, local and Tribal governments, public interest groups, environmental organizations, service groups, and more. In determining a fair spread across categories, no more than 60% of the advisory committee can come from a single categorical entity.
- Members must demonstrate notable commitment to environmental issues with extensive involvement, knowledge, or engagement with relevant material and/or affected communities.
- Members must demonstrate a working knowledge of Federal, State, and local government operations and systems.
- Members must demonstrate a notable commitment to Diversity, Equity, Inclusion and Accessibility, including for underserved communities.
- Members must demonstrate an ability to work in a consensus building process with a wide range of representative from diverse constituencies.
- Members must be able to contribute approximately 10 to 15 hours per month to HBCU–MSI AC activities, including the attendance at meetings and participating in the development of advice letters/reports and other material.
- Members must demonstrate potential for active and constructive involvement in HBCU–MSI AC work.

How to Submit Applications: Any interested person or organization may apply to be considered for an appointment to serve on the Historically Black Colleges and Universities and Minority Serving Institutions Advisory Council.

- Applications must include:

(1) contact information as outlined below:

Applicants must provide their: full legal name, preferred name if applicable, pronouns, date of birth, current home address, and phone number.

(2) resume or curriculum vitae (CV)

(3) statement of interest explaining why you would like to serve on this committee:

The statement of interest should describe how the nominee's background, knowledge, and experience would add value to the committee's work, and how the individual's qualifications would contribute to the overall diversity of the Historically Black Colleges and Universities and Minority Serving Institutions Advisory Council. To help the Agency in evaluating the effectiveness of its outreach efforts, please include in the statement of interest how you learned of this opportunity.

Please be aware that EPA's policy is that, unless otherwise prescribed by statute, members generally are appointed for a two-year term. For appointment consideration, interested nominees should submit the application materials electronically via email to Pradnya Bhandari at *HBCU-MSI.AC@epa.gov,* with the subject line HBCU–MSI AC, COMMITTEE APPLICATION PACKAGE 2024 for (Name of Nominee).

Jessica Loya,

Deputy Associate Administrator, Office of Public Engagement, Office of Public Engagement and Environmental Education, Office of the Administrator.

[FR Doc. 2024–09880 Filed 5–8–24; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–11937–01–OMS]

Good Neighbor Environmental Board

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of meeting.

SUMMARY: Under the Federal Advisory Committee Act, the Environmental Protection Agency (EPA) gives notice of a public meeting of the Good Neighbor Environmental Board (GNEB). The purpose of this meeting is for the board to discuss and approve its next charge topic(s) for the GNEB 21st report.

DATES: May 29, 2024, from 11:00 a.m.–3:00 p.m. (EST). A copy of the agenda will be posted at *www.epa.gov/faca/gneb.*

The meeting will be held virtually and in-person at the U.S. Environmental Protection Agency (EPA) headquarters located at 1200 Pennsylvania Avenue NW, Washington, DC 20460. The meeting is open to the public with limited access available on a first-come, first-served basis. Members of the public wishing to participate should contact Eugene Green at *green.eugene@epa.gov* by May 22nd.

Requests to make oral comments or submit written public comments to the board, should also be directed to Eugene Green at least five business days prior to the meeting. Requests for accessibility and/or accommodations for individuals with disabilities should be directed to Eugene Green at the phone number or email address listed below. To ensure adequate time for processing, please make requests for accommodations at least 10 business days prior to the meeting.

FOR FURTHER INFORMATION CONTACT: For information regarding the GNEB meeting, please contact Eugene Green at (202) 564–2432 or via email at *green.eugene@epa.gov.*

SUPPLEMENTARY INFORMATION: The GNEB is an independent federal advisory committee chartered under the Federal Advisory Committee Act, Public Law 92–463. Its mission is to advise the President and Congress of the United States on good neighbor practices along the U.S. border with Mexico. Its recommendations are focused on environmental infrastructure needs within the U.S. states contiguous to Mexico.

Dated: May 3, 2024.

Eugene Green,

Program Analyst.

[FR Doc. 2024–10097 Filed 5–8–24; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–R10–RCRA–2023–0638; FRL–11886–01–R10]

Idaho: Notice of Determination of Adequacy of Idaho's Research, Development and Demonstration Permit Provisions for Municipal Solid Waste Landfills

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Environmental Protection Agency (EPA) is approving Idaho's modification to its approved Municipal Solid Waste Landfill (MSWLF) permit program. On March 22, 2004, the EPA issued final regulations allowing Research, Development, and Demonstration (RD&D) permits to be issued to certain MSWLFs by approved states. On September 14, 2023, the Idaho Department of Environmental Quality submitted an application to the EPA seeking Federal approval of its RD&D requirements. The EPA has reviewed the application and determined it to be adequate.

DATES: This determination of adequacy will become effective July 8, 2024 without further notice unless the EPA receives adverse comments on or before July 8, 2024. If adverse comments are received, the EPA will review the comments and publish another **Federal Register** document responding to the comments and will either affirm or revise its initial decision.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R10–RCRA–2023–0638, at *https://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from regulations.gov. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: Domenic Calabro, U.S. EPA Region 10, 1200 6th Avenue, Suite 155, Seattle, WA 98101, (206) 553–6640, *calabro.domenic@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On March 22, 2004, the EPA issued a final rule amending the Municipal Solid Waste Landfill (MSWLF) criteria in the Code of Federal Regulations (CFR) at 40 CFR part 258 to allow for Research, Development and Demonstration (RD&D) permits (69 FR 13242). That rule allows for variances from specified criteria for a limited period of time, to be implemented through state-issued RD&D permits. RD&D permits are available only in states with approved MSWLF permit programs that have been modified to incorporate RD&D permit authority.

While states are not required to adopt this provision, those states that are interested in providing RD&D permits to owners and operators of MSWLFs must seek approval from the EPA before issuing such permits. Approval procedures for new provisions of 40 CFR part 258 are outlined in 40 CFR 239.12.

On September 21, 1993, the EPA published a final rule approving Idaho's MSWLF permit program (65 FR 453). On September 14, 2023, the Idaho Department of Environmental Quality applied for approval of its RD&D permit provisions, codified at Idaho Code 39–7421, Idaho Solid Waste Facilities Act.

II. Decision

After a thorough review of Idaho's revision package, the EPA determined that Idaho's RD&D permit provisions, as set out in Idaho Code 39–7421, Idaho Solid Waste Facilities Act, are adequate to ensure compliance with the Federal criteria as set out in 40 CFR 258.4.

*Authority:*This action is issued under the authority of sections 2002, 4005 and 4010(c) of the Solid Waste Disposal Act, as amended, 42 U.S.C. 6912, 6945 and 6949(a).

Dated: May 3, 2024.

Casey Sixkiller,

Regional Administrator, Region 10.

[FR Doc. 2024–10175 Filed 5–8–24; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

[OMB 3060–0496; FR ID 217978]

Information Collection Being Reviewed by the Federal Communications Commission Under Delegated Authority

AGENCY: Federal Communications Commission.

ACTION: Notice and request for comments.

SUMMARY: As part of its continuing effort to reduce paperwork burdens, and as required by the Paperwork Reduction Act (PRA) of 1995, the Federal Communications Commission (FCC or the Commission) invites the general public and other Federal agencies to take this opportunity to comment on the following information collection. Comments are requested concerning: whether the proposed collection of information is necessary for the proper performance of the functions of the Commission, including whether the information shall have practical utility; the accuracy of the Commission's burden estimate; ways to enhance the quality, utility, and clarity of the information collected; ways to minimize the burden of the collection of information on the respondents, including the use of automated collection techniques or other forms of information technology; and ways to further reduce the information collection burden on small business concerns with fewer than 25 employees. The FCC may not conduct or sponsor a collection of information unless it displays a currently valid control number. No person shall be subject to any penalty for failing to comply with a collection of information subject to the PRA that does not display a valid Office of Management and Budget (OMB) control number.

DATES: Written PRA comments should be submitted on or before July 8, 2024. If you anticipate that you will be submitting comments, but find it difficult to do so within the period of time allowed by this notice, you should advise the contact listed below as soon as possible.

ADDRESSES: Direct all PRA comments to Nicole Ongele, FCC, via email *PRA@fcc.gov* and to *nicole.ongele@fcc.gov.*

FOR FURTHER INFORMATION CONTACT: For additional information about the information collection, contact Nicole Ongele, (202) 418–2991.

SUPPLEMENTARY INFORMATION:

OMB Control Number: 3060–0496.

Title: ARMIS Operating Data Report, FCC Report 43–08.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for-profit entities.

Number of Respondents and Responses: 49 respondents; 49 responses.

Estimated Time per Response: 8 hours.

Frequency of Response: Annual reporting requirement.

Obligation to Respond: Mandatory. Statutory authority for this information collection is contained in 47 U.S.C. 219 and 220 of the Communications Act of 1934, as amended.

Total Annual Burden: 392 hours.

Total Annual Cost: No cost.

Needs and Uses: The information contained in FCC Report 43–08 has helped the Commission fulfill its regulatory responsibilities. Automated reporting of these data greatly enhances the Commission's ability to process and analyze the extensive amounts of data provided in the reports. Automating and organizing data submitted to the Commission facilitate the timely and efficient analysis of revenue requirements, rates of return and price caps, and provide an improved basis for auditing and other oversight functions. Automated reporting also enhances the Commission's ability to quantify the effects of policy proposals. The Commission has granted all carriers forbearance from many of the requirements of ARMIS 43–08 conditioned on approval of a data retention compliance plan and continued submission of certain ARMIS 43–08 data related to access lines in service to customers.

Federal Communications Commission.

Marlene Dortch,

Secretary, Office of the Secretary.

[FR Doc. 2024–10143 Filed 5–8–24; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL ELECTION COMMISSION

Sunshine Act Meetings

TIME AND DATE: Tuesday, May 14, 2024, at 10:00 a.m. and its continuation at the conclusion of the open meeting on May 16, 2024.

PLACE: 1050 First Street NE, Washington, DC and virtual. (This meeting will be a hybrid meeting.)

STATUS: This meeting will be closed to the public.

MATTERS TO BE CONSIDERED: Compliance matters pursuant to 52 U.S.C. 30109. Matters concerning participation in civil actions or proceedings or arbitration.

* * * * *

CONTACT PERSON FOR MORE INFORMATION: Judith Ingram, Press Officer, Telephone: (202) 694–1220.

(Authority: Government in the Sunshine Act, 5 U.S.C. 552b)

Vicktoria J. Allen,

Deputy Secretary of the Commission.

[FR Doc. 2024–10264 Filed 5–7–24; 4:15 pm]

BILLING CODE 6715–01–P

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The public portions of the applications listed below, as well as other related filings required by the Board, if any, are available for immediate inspection at the Federal Reserve Bank(s) indicated below and at the offices of the Board of Governors. This information may also be obtained on an expedited basis, upon request, by contacting the appropriate Federal Reserve Bank and from the Board's Freedom of Information Office at *https://www.federalreserve.gov/foia/request.htm.* Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)).

Comments received are subject to public disclosure. In general, comments received will be made available without change and will not be modified to remove personal or business information including confidential, contact, or other identifying information. Comments should not include any information such as confidential information that would not be appropriate for public disclosure.

Comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors, Ann E. Misback, Secretary of the Board, 20th Street and Constitution Avenue NW, Washington, DC 20551–0001, not later than June 10, 2024.

A. Federal Reserve Bank of Chicago (Colette A. Fried, Assistant Vice President) 230 South LaSalle Street, Chicago, Illinois 60690–1414. Comments can also be sent electronically to *Comments.applications@chi.frb.org:*

1. *Wintrust Financial Corporation, Rosemont, Illinois;* to merge with Macatawa Bank Corporation, and thereby indirectly acquire Macatawa Bank, both of Holland, Michigan.

Board of Governors of the Federal Reserve System.

Michele Taylor Fennell,

Deputy Associate Secretary of the Board.

[FR Doc. 2024–10164 Filed 5–8–24; 8:45 am]

BILLING CODE P

FEDERAL RESERVE SYSTEM

[Docket No. OP–1831]

Expansion of Fedwire® Funds Service and National Settlement Service Operating Hours

AGENCY: Board of Governors of the Federal Reserve System.

ACTION: Request for comment.

SUMMARY: The Board of Governors of the Federal Reserve System (Board) is seeking input on a proposal to expand the operating hours of the Fedwire® Funds Service and the National Settlement Service (NSS). The Board proposes to expand the operating hours of the Fedwire Funds Service to 22 hours per day, 7 days per week, every day of the year (22x7x365) and to correspondingly expand the operating hours of NSS, with NSS closing 30 minutes earlier than the Fedwire Funds Service. At this time, the Board is not considering expanding operating hours for the Fedwire Securities Service. The Board requests comments on the potential benefits, risks, and implementation considerations of the proposal.

DATES: Comments on the proposed actions must be received on or before July 8, 2024.

ADDRESSES: You may submit comments, identified by Docket No. OP–1831, by any of the following methods:

- *Agency website: http://www.federalreserve.gov.* Follow the instructions for submitting comments at *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm.*
- *Email: regs.comments@federalreserve.gov.* Include docket number in the subject line of the message.
- *FAX:* (202) 452–3819 or (202) 452–3102.
- *Mail:* Ann Misback, Secretary, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue, NW, Washington, DC 20551.

All public comments will be made available on the Board's website at *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm* as submitted, unless modified for technical reasons or to remove personally identifiable information at the

commenter's request. Accordingly, comments will not be edited to remove any identifying or contact information. Public comments may also be viewed electronically or in paper in Room 146, 1709 New York Avenue NW, Washington, DC 20006, between 9:00 a.m. and 5:00 p.m. eastern time (ET) on weekdays.

FOR FURTHER INFORMATION CONTACT: Mark Magro, Manager, Division of Reserve Bank Operations and Payment Systems (202–452–3944); Ann Sun, Lead Financial Institution Policy Analyst, Division of Reserve Bank Operations and Payment Systems (202–912–7938); or Gavin Smith, Senior Counsel, Legal Division (202 452–3474); or Corinne Milliken Van Ness, Senior Counsel, Legal Division (202–452–2421), Board of Governors of the Federal Reserve System. For users of Telecommunications Device for the Deaf (TDD), contact (202–263–4869.)

SUPPLEMENTARY INFORMATION:

I. Background

The Federal Reserve has a long-standing policy objective to foster a safe and efficient U.S. payment system. The Federal Reserve advances its objectives for the payment system through, among other things, the Federal Reserve Banks' (Reserve Banks) operation of two large-value payment services: the Fedwire® Funds Service and NSS.[1] The Fedwire Funds Service is a real-time gross settlement (RTGS) service that allows participating financial institutions (participants) to send and receive individual electronic funds transfers up to one penny less than $10 billion in value that are immediate to participants, final, and irrevocable. NSS is a multilateral settlement service that allows for immediate, final, and irrevocable settlement of obligations that arise from private-sector clearing arrangements, such as check clearinghouses, a private-sector ACH network, and securities settlement systems.[2] Together, these services, alongside a large-value payment service operated by the private sector, provide the backbone for the nation's payment system and thereby support a significant amount of economic activity in the United States, including large-value domestic financial market transactions, the U.S. dollar leg of many cross-border transactions, and private-sector payment clearing arrangements.[3]

The Federal Reserve has consistently improved its payment services to meet the evolving needs of the U.S. economy. As technological advancements and globalization of commerce continue to drive change in the large-value payment landscape, the Board believes that expanding the availability of the Fedwire Funds Service and NSS would enhance the safety and efficiency of the U.S. payment system by extending the hours in which settlement in risk-free central bank money can occur.[4] Thus, the Board is proposing to expand the operating hours of the Fedwire Funds Service to 22 hours per day, 7 days per week, every day of the year and to expand the operating hours of NSS correspondingly, with NSS closing 30 minutes earlier than the Fedwire Funds Service.[5] The Board recognizes that a significant expansion in operations for large-value payments in the short term might pose burdensome technical and operational changes at a time when the industry will also be adjusting to the new ISO® 20022 message format for large-value payments and instant payment services.[6] Therefore, the Board proposes that the expansion to 22x7x365 would be implemented no sooner than two years after the migration of the Fedwire Funds Service to the ISO 20022 standard, scheduled for March 2025. The final implementation timeline for 22x7x365 will be determined based on input from this request for comment, among other relevant considerations.

The Board is seeking comment on the potential benefits, risks, costs, and other considerations of expanded hours for the Fedwire Funds Service and NSS, as described in Section II. The Board is also requesting comment on implementation considerations, as described in Section III. As noted, the Board is not considering expanding operating hours for the Fedwire Securities Service at this time.

II. Proposed Action

A. Proposal

The Board proposes to expand the operating hours of Fedwire Funds Service to 22x7x365 and to correspondingly expand the operating hours of NSS. It is anticipated that if the proposal is adopted NSS would continue to close at 6:30 p.m. ET, 30 minutes prior to the close of Fedwire Funds Service at 7:00 p.m. ET. Both services will maintain their current opening time of 9:00 p.m. ET of the preceding calendar day for the proposed weekend operating days. Table 1 summarizes the proposed changes to operating hours for the Fedwire Funds Service and NSS.

[1] ''Fedwire'' is a registered service mark of the Federal Reserve Banks.

[2] Settlement files submitted to NSS can be for an amount up to one penny less than $10 trillion; each entry in a settlement file can be for an amount up to one penny less than $100 billion.

[3] The private-sector large-value payment service is CHIPS®, which is owned and operated by The Clearing House Payments Company L.L.C. (TCH). ''CHIPS'' is a registered service mark of TCH. While the Fedwire Funds Service supports large-value payments (often referred to as ''wholesale'' payments), not all payments sent through the Fedwire Funds Service would be considered large value. For example, while the average value of a payment in 2023 on the Fedwire Funds Service was $5.625 million, the median value was approximately $19,000. In general, smaller-value, general purpose payments sent by consumers and businesses are made using services designed for smaller value (''retail'') transactions such as the Reserve Banks' check clearing and automated clearinghouse (ACH) services, and the FedNow® Service for instant payments. ''FedNow'' is a registered service mark of the Federal Reserve Banks.

[4] Central bank money is a liability of the central bank that can be used for settlement purposes and is considered free of credit and liquidity risks. Central bank money has traditionally taken two forms: cash and reserve balances held by eligible financial institutions at the central bank.

[5] Fedwire Funds Service is currently open from 9:00 p.m. ET of the preceding calendar day to 7:00 p.m. ET, five days per week, Monday through Friday excluding holidays observed by the Reserve Banks. NSS is open from 9:00 p.m. to 6:30 p.m. ET, five days per week, Monday through Friday excluding holidays observed by the Reserve Banks. The Federal Reserve has historically provided at least 30 minutes between the close of NSS and the close of the Fedwire Funds Service, recognizing that the Fedwire Funds Service is the primary alternative for orderly and efficient settlement of bilateral obligations in case a settlement arrangement is unable to complete its multilateral settlement through NSS.

[6] ''ISO'' is a registered service mark of the International Organization for Standardization.

For example, the FedNow Service, which was launched in July 2023, is an instant payments service. Instant payments allow consumers and businesses to send and receive funds from their accounts at banks and credit unions in real time, any time of day, any day of the year, with immediate funds availability to receivers.

TABLE 1—PROPOSED CHANGES TO OPERATING HOURS FOR THE FEDWIRE FUNDS SERVICE AND NSS

	Current operating hours	Proposed operating hours
Fedwire Funds Service[7]	9:00 p.m. ET–7:00 p.m. ET, Monday–Friday, excluding holidays.	9:00 p.m. ET–7:00 p.m. ET, every day.
NSS[8]	9:00 p.m. ET–6:30 p.m. ET, Monday–Friday, excluding holidays.	9:00 p.m. ET–6:30 p.m. ET, every day.

B. Rationale for Proposal

The Federal Reserve has expanded operating hours for the Fedwire Funds Service and NSS over time in response to changing market conditions and industry demand. Most recently, the Board received public comments on expanded hours for the Fedwire Funds Service and NSS in response to **Federal Register** notices related to the development of the FedNow Service.[9] Certain commenters indicated that expanded hours would provide a means for participants in retail instant payment services to manage liquidity needs related to instant payment activity on a round-the-clock basis.[10] To address this industry input and meet FedNow Service implementation timelines, the Board determined that liquidity management transfer functionality should be provided within the FedNow Service at the time of its launch in July 2023. However, the Board indicated it would continue to explore expanded hours for the Fedwire Funds Service and NSS, given the broad benefits that expanded hours could provide to financial markets and the payment systems and market infrastructures that support those markets.[11] Subsequently, in a 2022 notice regarding the implementation of the ISO 20022 format for the Fedwire Funds Service, the Board indicated that the Reserve Banks would conduct engagement with industry stakeholders as part of its analysis of expanded operating hours for the Fedwire Funds Service and NSS.[12]

The Reserve Banks conducted this engagement through outreach sessions with a broad range of stakeholders, including large global financial institutions, small and mid-sized banks in different regions, and nonbanks and service providers, to better understand the needs and concerns of industry. While these industry outreach sessions were informal and not as comprehensive as an information collection conducted through the broader **Federal Register** notice process, stakeholders raised several initial themes. Overall, industry stakeholders that are active in global payments markets expressed strong support for an expansion of Fedwire Funds Service and NSS operating hours up to 24x7x365, stating that expanded hours would enhance the ability of cross-border payments and international commerce to be conducted in U.S. dollars and help preserve the status of the U.S. dollar as the preferred currency for global settlements.[13] In addition, industry stakeholders noted that while 24x7x365 operating hours would be an ideal state in the longer term, other payment system improvement initiatives should be prioritized ahead of an expansion, including implementation of the new FedNow Service for instant payments and ISO 20022 migration of the Fedwire Funds Service. In general, these stakeholders noted that shifting large-value payment operations to full 24x7x365, with no downtime to accommodate system changes and other operational activities, would be challenging to implement in the shorter term.[14]

Smaller banks provided differing perspectives on the benefits of Fedwire Funds Service and NSS expanded hours, with some institutions expressing a lack of pressing need and business case compared with the level of investment required to operate on a 24x7x365 basis. Other institutions saw value in expanded hours to provide increased flexibility in operating hours among West Coast banks or to maximize time available to recover from an operational issue on the same business day. Overall, smaller banks noted the importance of maintaining optionality to participate in Fedwire Funds Service and NSS operating hours such that banks are not required to operate or otherwise maintain staff during expanded hours.

Concurrent with the Federal Reserve's consideration of expanded operating hours for the Fedwire Funds Service and NSS, the international community has been advancing initiatives to improve the cost, speed, accessibility, and transparency of cross-border payments. In 2020, the G20 leaders endorsed the Roadmap for Enhancing Cross-Border Payments, which set out a series of ''building blocks'' to address the frictions underlying the challenges associated with cross-border payments.[15] Building Block 12 focused on extending and aligning the operating hours of existing payment infrastructures and arrangements across jurisdictions, particularly RTGS systems. Cross-jurisdiction alignment could speed up cross-border payments, improve liquidity management, and reduce settlement risk, among other benefits.[16] Global alignment of large-value RTGS system operating hours has been a driver of past expansions for the

[7] The Fedwire Funds Service begins processing online payment orders beginning at 9:00 p.m. ET on the preceding calendar day. The Fedwire Funds Service begins processing online nonvalue messages at 8:35 p.m. ET on the preceding calendar day. The cutoff time for special account messages is 5:00 p.m. ET, the cutoff time for customer messages is 6:45 p.m. ET, and the cutoff time for bank messages is 7:00 p.m. ET. The Fedwire Funds Service closes at 7:00 p.m. ET.

[8] The file processing window for NSS begins at 9:00 p.m. ET on the preceding calendar day and closes at 6:30 p.m. ET.

[9] *See* 83 FR 57351 (Nov. 15, 2018) and 84 FR 39297 (Aug. 9, 2019).

[10] The 24x7x365 nature of instant payments requires banks to have sufficient liquidity to settle instant payments at any time, any day of the week. As a result, banks need a method to fund accounts used to settle instant payment transactions during hours when large-value payment services are not currently open. See 83 FR 57351 (Nov. 15, 2018).

[11] *See* 84 FR 39297 (Aug. 9, 2019). The Board indicated that further analysis was needed to evaluate fully the relevant operational, risk, and policy considerations of expanded Fedwire Funds Service and NSS operating hours.

[12] *See* 87 FR 64217 (Oct. 24, 2022).

[13] Certain industry stakeholders have also expressed these views via the industry-led Payments Risk Committee. *See Payments Risk Committee: Fedwire Expanded Hours Whitepaper,* available at *https://www.newyorkfed.org/medialibrary/microsites/prc/files/2021/prc-fedwire-expanded-hours-considerations-white-paper.*

[14] In outreach sessions, industry stakeholders indicated that the elimination of downtime between the close and open of the Fedwire Funds Service and NSS could pose a more significant challenge than expanding operating hours into the weekend.

[15] See *Financial Stability Board: Enhancing Cross-border Payments: Stage 3 Roadmap* available at *https://www.fsb.org/wp-content/uploads/P131020-1.pdf.* See also *Financial Stability Board: Enhancing Cross-border Payments: Stage 1 report to the G20* available at *https://www.fsb.org/wp-content/uploads/P090420-1.pdf* which discusses key frictions in cross-border payments.

[16] In February 2023, the Financial Stability Board published an updated and prioritized Roadmap centered on three priority themes, which includes the extension and alignment of the operating hours of key payment systems. Available at *https://www.fsb.org/2023/02/g20-roadmap-for-enhancing-cross-border-payments-priority-actions-for-achieving-the-g20-targets/.*

Fedwire Funds Service because of the risk-reducing benefits.[17] Though the gaps in operating hours between the Fedwire Funds Service and other RTGS systems have decreased over time, gaps still remain, in particular during weekend hours. Expanding the operating hours of the Fedwire Funds Service and NSS into the weekend would be consistent with the broader G20 agenda and would be consistent with the actions of other central banks that are considering or have already expanded operating hours for their large-value payment services.[18]

Also, the Federal Reserve recognizes that payment infrastructure needs to evolve to support commerce that is increasingly being conducted outside traditional business hours. Expanded hours for the Fedwire Funds Service and NSS alongside the FedNow Service would bring the benefits of near round-the-clock payments for large-value, wholesale payments, such as multi-million dollar business invoices, real estate transactions, and insurance payouts, ensuring that the evolution of commerce is supported across retail and wholesale infrastructures.[19]

C. Analysis of Options for Expanded Hours

While 24x7x365 operating hours for the Fedwire Funds Service and NSS remains a possibility in the longer term, the Board recognizes that the shift to full round-the-clock operations, with no downtime in operations to complete end-of-day processing or implement system upgrades for large-value payment services, may pose challenges in the shorter term. The Board considered multiple alternatives to the proposed 22x7x365, including the addition of a short weekend window of operating hours on Saturday and/or Sunday; 22 hours per day, 6 days per week; 24 hours per day, 5 days per week; and 24x7x365 operating hours. Overall, the Board believes that expanding to 22x7x365 could achieve many of the benefits of 24x7x365 hours while giving the industry and Reserve Banks time to adjust technology and operations for potential future expansions of operating hours of the Fedwire Funds Service and NSS. Participation in expanded hours would be voluntary. The Board is proposing to extend the current 22x5 Fedwire Funds Service and NSS operating hours to 22x7x365 no sooner than two years after the implementation of the ISO 20022 message format for the Fedwire Funds Service, scheduled for March 2025. (See Section III for a further discussion on implementation considerations).

A key reason for considering a 22x7x365 expansion of Fedwire Funds Service and NSS operating hours is a faster and less costly implementation than a full 24x7x365 expansion, which would help achieve the Board's safety and efficiency policy objectives for large-value payments in the nearer term. In addition, industry feedback to date underscored that investment in technical infrastructure modernization for participants to accommodate round-the-clock availability would pose challenges that could be reduced by a shorter move to 22x7x365 operating hours.

An expansion of Fedwire Funds Service and NSS operating hours to 22x7x365 could also reduce costs and risks to the industry and the Federal Reserve relative to an expansion to 24x7x365 operations. For example, an expansion to 22x7x365 operating hours could allow participants to gradually adapt to seven-day operations for wholesale payments, which could reduce operational risks. Additionally, lessons learned from the expansion could be applied to the potential future development of full 24x7x365 operations for the Fedwire Funds Service and NSS.

D. Benefits, Costs, Risks, and Other Considerations

1. Benefits

Expanding current Fedwire Funds Service and NSS operating hours from five to seven days per week, each day of the year, could improve the safety and efficiency of both domestic and global large-value U.S. dollar payments. Domestically, expanded hours could allow systemically important financial market utilities (FMUs) (that is, a large-value payment service, securities and derivatives clearinghouses, and securities settlement services) and retail payment arrangements (that is, check clearinghouses, an ACH network, and an instant payment service) that leverage the Fedwire Funds Service and/or NSS to have broader options for settlement of time-critical payments.[20] Settlement outside of traditional windows could reduce credit risk in certain FMUs and retail payment arrangements by narrowing the time gap between the creation of payment obligations and the discharge of those obligations in final funds, thereby reducing the potential for spillover effects in the financial system from settlement disruptions. To the extent that FMUs and retail payment arrangements operate outside of traditional windows, these firms could have the option to receive or send funds in central bank money seven days per week, potentially improving their operational efficiency or reducing the build-up of credit risk on days when Fedwire Funds Service and NSS are not currently operating. Expanded hours might also spur new or enhanced private-sector payment solutions that leverage the Fedwire Funds Service and/or NSS, or enable financial market trading and lending activity that previously could not be supported during weekend hours.[21] Finally, as noted above, expanded hours for the Fedwire Funds Service and NSS alongside the FedNow Service would bring the benefits of near round-the-clock payments for large-value consumer and business payments, such

[17] *See* 59 FR 8981 (Feb. 24, 1994). Foreign exchange settlement risk is also commonly known as ''Herstatt risk.'' The name comes from an episode in which a German bank, the Herstatt Bank, was closed by its supervisor after the bank had received deutsche mark payments for foreign exchange transactions, but before it provided U.S. dollars to its counterparties in those transactions. Overlap in central bank services operating hours can mitigate foreign exchange settlement risk by providing an opportunity to shorten the time between the settlement of both legs of a foreign exchange transaction, including enabling simultaneous settlement.

[18] A number of central banks, such as those in Mexico and South Africa, have operated 24x7x365 large-value payment services for some time. Other central banks, including those in India and Switzerland, operate at near 24x7x365. In the United Kingdom, the Bank of England has announced that its next-generation large-value payment service will be capable of near 24x7x365 operations by 2024. The Bank of England will consider extending the operating hours of its large-value payment service in line with the industry's demand. *See* the Bank of England's Roadmap for Real-Time Gross Settlement service beyond 2024, available at *https://www.bankofengland.co.uk/paper/2022/roadmap-for-real-time-gross-settlement-service-beyond-2024.*

[19] The FedNow Service supports real-time, immediate end-to-end instant payments between end user senders and receivers, with immediate funds availability to receivers. The Fedwire Funds Service supports large-value payments that are either between banks only or intended for end-user receivers, with no immediate funds availability requirement for payments to end user receivers.

[20] Currently, the FedNow Service provides liquidity management transfer capability for FedNow participants and participants in a private-sector instant payment service to transfer funds to support instant payment liquidity needs during certain hours including when the Fedwire Funds Service is closed. While the hours of liquidity management transfers in FedNow might be adjusted if Fedwire Funds Service hours are expanded, transfers would remain available during the two-hour Fedwire Funds Service closure.

[21] *See the Committee on Payments and Market Infrastructures final report* ''*Extending and aligning operating hours for cross-border payments,*'' *available at https://www.bis.org/cpmi/publ/d203.pdf.*

as multi-million dollar business invoices, real estate transactions, and insurance payouts.

Expanded hours would also facilitate greater overlap and reduced gaps between the operating hours of the Fedwire Funds Service/NSS and key large-value payment services in other jurisdictions. This overlap and reduction in gaps would support more efficient cross-border payments through faster settlement and improved liquidity management. For example, some industry feedback highlighted the value of Sunday operating hours to support payment flows in the Middle East and North Africa region. Increased overlap in operating hours could provide more opportunities to settle cross-currency payments simultaneously via new or existing payment-versus-payment mechanisms and arrangements, thereby reducing settlement risk and potentially allowing for greater transparency in global foreign exchange (FX) markets.[22] Increased overlap and reduced gaps in operating hours could also speed up settlement of large-value corporate trade payments made through correspondent arrangements by reducing or eliminating the time gap between the U.S. leg of a payment and the leg of the payment in a foreign jurisdiction. Expanded operating hours would be consistent with the actions of other central banks, some of which have already undertaken an expansion of operating hours for their large-value payment services by targeting near or full 24x7x365 operations or by considering or positioning themselves for future expansion.[23]

2. Costs and Risks

The potential benefits of expanding Fedwire Funds Service and NSS operating hours to 22x7x365 need to be weighed against potential costs and risks. Expanded hours would require operational and technical changes that would impose costs on the Reserve Banks and on institutions that participate in the Fedwire Funds Service and NSS. The magnitude of costs would vary by institution. Some institutions have cited the potential for significant costs related to upgrades of legacy infrastructure, as well as increased staffing, to support expanded hours. Others have indicated that costs would be more incremental because their institutions could build on existing infrastructure that they use to support 24x7x365 instant payments. The Board is seeking comment on the cost burden to industry stakeholders of moving to 22x7x365 operations, as well as costs related to potential 24x7x365 operations in the future. Reserve Bank costs are discussed in Section 3.a.

In addition to the potential financial impact, extending current operating hours to every day of the year could generate additional risks to participants, the Reserve Banks, and the U.S. financial system more broadly.[24] For example, transferring funds to meet potential rapid deposit outflows during weekends and holidays could exacerbate liquidity issues for a bank in crisis. This risk could have financial stability implications if large deposit outflows experienced by a single participant created contagion to other participants.

The two-hour window between 7:00 p.m. and 9:00 p.m. ET on Saturday and Sunday under the Board's proposal to expanded hours would serve as a pause in transferring funds to meet deposit outflows.[25] Participants experiencing outflows could potentially utilize this time period to implement liquidity and risk management measures to address outflows. The Board is seeking comments on the likelihood that expanding Fedwire Funds Service and NSS hours would exacerbate liquidity risks arising from deposit outflows, as well as any additional risk controls that would be needed during expanded hours. Relatedly, the Board recognizes that participants' ability to access funding during expanded weekend and holiday hours will be important and seeks comments on the potential benefits and costs of extending discount window operations.

Expanded operating hours could also potentially increase operational and financial risks to participants and the Reserve Banks by expanding the time during which cyber-attacks or other operational disruptions could take place. While these risks are not new to the financial sector, the Board is seeking to understand the industry's readiness to manage these types of risks on a near round-the-clock basis.

3. Other Policy Considerations

The proposed expansion of operating hours to 22x7x365 would constitute major enhancements to the Fedwire Funds Service and NSS. Under longstanding Board policy, any potential new payment service or major enhancements to an existing service must meet the following criteria: (a) the Federal Reserve must expect to achieve full cost recovery of costs over the long run, (b) the Federal Reserve must expect that its providing the service will yield a clear public benefit, and (c) the service should be one that other providers alone cannot be expected to provide with reasonable effectiveness, scope, and equity.[26] An analysis of these criteria is set forth below.

a. Cost Recovery

Section 11A of the Federal Reserve Act, as added by the Monetary Control Act of 1980, requires that fees for Federal Reserve Bank payment services be set in accordance with the principle that, over the long run, those fees recover the costs of providing the services.[27] In addition, Board policy specifies that each major service category offered by the Federal Reserve must separately satisfy the cost recovery objective of the Monetary Control Act: in the long run, aggregate revenues should match costs.[28]

Initial analysis suggests that over the long run, the Reserve Banks would be able to recover the costs associated with the proposed 22x7x365 expanded operating hours. Discussions with industry stakeholders about the need for expanded hours to support cross-border activity, innovative use cases, and additional settlement opportunities for systemically important and large-value transactions support the assumption that, over time, expanding Fedwire Funds Service and NSS hours would generate increases in volume and revenue. The Reserve Banks completed a cost estimate analysis that included

[22] As explored in the ''Committee on Payments and Market Infrastructures final report: Extending and aligning operating hours for cross-border payments'', expansion of large-value payment system operating hours would also add to the current global settlement window (*i.e.,* the time period during which the largest number of large-value RTGS systems are simultaneously operating).

[23] See footnote 20 regarding Mexico, South Africa, India, Switzerland and the United Kingdom, for example.

[24] It is anticipated that not all participants may choose to participate in the expanded weekend hours at launch. Please see section III.B. for a discussion of optional participation in a 22x7x365 operating environment of the Fedwire Funds Service and NSS.

[25] See Section II.A. Proposal for the proposed operating hours on Saturday and Sunday.

[26] *See* Board of Governors of the Federal Reserve System, ''The Federal Reserve in the Payments System,'' (issued 1984; revised 1990). Available at Federal Reserve Board—Policies: The Federal Reserve in the Payments System.

[27] Specifically, section 11A provides that, ''[o]ver the long run, fees shall be established on the basis of all direct and indirect costs actually incurred in providing the Federal Reserve services priced, including interest on items credited prior to actual collection, overhead, and an allocation of imputed costs which takes into account the taxes that would have been paid and the return on capital that would have been provided had the services been furnished by a private business firm, except that the pricing principles shall give due regard to competitive factors and the provision of an adequate level of such services nationwide.'' 12 U.S.C. 248a.

[28] *See* ''The Federal Reserve in the Payments System,'' *supra* note 28.

system changes and additional staffing during the weekends. The Reserve Banks expect these costs would be offset by increased revenue, subject to various factors such as the competitive and/or economic environment in future years, new product enhancement opportunities, and potential Fedwire Funds Service and NSS pricing changes. In addition, Reserve Bank operational costs may be lower for expanded hours due to efficiency gains that could arise from leveraging operations and customer support staff that are already in place for the FedNow Service. The Board will conduct a full analysis of long-term cost recovery impacts to the Fedwire Funds Service and NSS based on input received on the proposal.

b. Public Benefit

The Board believes the expansion of operating hours for the Fedwire Funds Service and NSS could have several important safety and efficiency benefits. From a domestic perspective, expanded hours could reduce credit risk and improve safety in the financial system by narrowing the time gap between the creation of payment obligations and the discharge of those obligations in final funds, improve operational efficiency in FMUs and retail payment arrangements, and spur innovations in large-value payments such as weekend interbank lending markets. From an international perspective, expanded hours would increase overlap and reduce gaps between the operating hours of the Fedwire Funds Service and NSS and other key large-value real time gross settlement systems internationally and would support greater efficiency in cross-border payments. Please see previous section II.D.1. for a full discussion of potential benefits.

c. Other Providers

Board policy also requires that for any new service or major service change, the service should be one that other providers alone cannot be expected to provide with reasonable effectiveness, scope, and equity.[29] Today, to provide final settlement, the private-sector large-value payment service relies on the Fedwire Funds Service to support its settlement process. Thus, this service would likely not be able to effectively expand its operating hours without a similar expansion in the operating hours of the Fedwire Funds Service. In terms of scope and equity, today the Fedwire Funds Service and NSS are broadly accessible to eligible financial institutions across the country on equal terms.[30] Thus, the Federal Reserve could offer financial institutions similarly broad access to expanded operating hours.

III. Implementation Considerations

This section describes (A) the potential timeline for an expansion of the Fedwire Funds Service and NSS operating hours from 22x5 to 22x7x365, and considerations that will inform the final timeline, (B) considerations for optional participation in a 22x7x365 operating environment, (C) other potential enhancements to the Fedwire Funds Service and NSS, and (D) the availability of the discount window.

A. Timeline for Proposal

The implementation timeline for the expansion of operating hours to 22x7x365 and potentially to 24x7x365 in the future will depend on many factors, including the operational and technical challenges to the Federal Reserve and participants of implementing and adopting potential operating hours expansions, industry preferences related to timing, demand for 22x7x365 and 24x7x365 operating hours among participants, and interdependencies with other developments in the payments landscape. Should the Board decide to proceed with the proposed expansion to 22x7x365, it will consider these and other factors before determining the final timeline.

Based on initial industry outreach conducted after the 2022 **Federal Register** notice for the implementation of the ISO 20022 standard for the Fedwire Funds Service, there is broad consensus from stakeholders that expanding Fedwire Funds Service and NSS operating hours should not occur until after the implementation of the ISO 20022 standard for the Fedwire Funds Service scheduled for March 2025. Initial analysis suggests an expansion of Fedwire Funds Service and NSS operating hours to 22x7x365 could potentially be achieved no sooner than two years after the implementation of the ISO 20022 message format for the Fedwire Funds Service. As a result, if public comments in response to this notice indicate support for the proposed expansion to 22x7x365 operating hours for the Fedwire Funds Service and NSS, the Federal Reserve would expand operating hours to 22x7x365 no sooner than 2027.

In determining an implementation timeline for 22x7x365 operating hours, the Board will consider feedback received in response to this notice, including whether an interim step short of 22x7x365 would be desirable. Key feedback areas will include the extent to which participants would benefit from weekend operating hours for the Fedwire Funds Service and NSS being made available as soon as practicable, and the extent to which participants may need to adjust their staffing, internal systems, and processes to take advantage of weekend operating hours. Furthermore, the eventual timeline will also reflect interdependencies between the development and adoption of expanded operating hours for the Fedwire Funds Service and NSS and other initiatives.

An expansion to full 24x7x365 operating hours for the Fedwire Funds Service and NSS is a possibility in the future. The Board is interested in collecting feedback from industry on constraints, preferences, and demand related to full 24x7x365 operating hours. If the Board does propose to expand operating hours further to 24x7x365, it would seek public comment in a separate proposal.

B. Considerations for Optional Participation in a 22x7x365 Operating Environment of the Fedwire Funds Service and NSS

In alignment with current service terms and in response to industry feedback from smaller institutions, participation in proposed 22x7x365 operating hours for the Fedwire Funds Service and NSS would be optional. Currently, a Fedwire Funds Service participant, for example, may decide not to be open to process payment orders sent to it over the Fedwire Funds Service during overnight hours. Similarly, an institution that participates in a private-sector clearing arrangement for which transactions are settled through NSS may be allowed under the rules of the clearing arrangement (i) not to send or receive transactions using the clearing arrangement during overnight hours (and thus not trigger any settlement obligations) or (ii) to instruct the agent for the NSS settlement arrangement not to include any debit or credit entries for the institution or other institutions for which it settles in any settlement files submitted to NSS during that time.[31]

[29] *See* ''The Federal Reserve in the Payments System,'' *supra* note 28.

[30] Depository institutions may access these services either directly (settling transactions in their Federal Reserve account) or indirectly (through another depository institution that acts as a correspondent bank for the institution).

[31] Only institutions that are settlers in an NSS settlement arrangement may settle debit or credit entries in an NSS settlement file. Settlers may settle debit or credit entries for their own account or on behalf of other institutions that participate in the

The Board believes the optionality should be maintained during any expanded hours.

If a participant chooses not to operate during some or all potential weekend and holiday operating hours of the Fedwire Funds Service, the participant might continue to receive payment orders through the Fedwire Funds Service, just as some participants today receive payment orders while they are not operating during overnight hours. If a participant chooses not to operate during the weekend or on a holiday, it would not be required to take action on any payment orders sent to it during those days if they are not funds-transfer business days for the participant. Alternatively, if a participant wishes to operate only during part of the weekend and holiday operating hours, it may set cutoff or closing times for its funds-transfer business day, after which it would not be required to take action on a payment order sent to it until its next funds-transfer business day.[32] For NSS, if a participant does not settle transactions through the NSS settlement arrangement during weekend or holiday operating hours, it may be unable to send or receive transactions through the private-sector clearing arrangement during that time depending on the rules of the clearing arrangement.

Although optionality with respect to participation in a 22x7x365 operating environment may allow some participants to avoid certain costs associated with an expansion in operating hours of the Fedwire Funds Service and NSS, it may also present certain challenges. For example, a participant that chooses not to operate (that is, send payments), but continues to receive payments in its master account during certain Fedwire Funds Service operating hours, could become a source of trapped liquidity, which could lead to the participant's counterparties implementing liquidity management measures such as restricting payments to the participant while they are offline.[33] Further, such optionality could, over time, hinder broad adoption of expanded hours across the participant base, which could limit the full benefits of 22x7x365 Fedwire Funds Service and NSS. Notwithstanding these considerations, the Board is not contemplating a change to the participation model for Fedwire Funds Service and NSS.

C. Potential Other Enhancements to Fedwire Funds Service and NSS

While this notice focuses on the proposal to expand operating hours to 22x7x365, the Board recognizes there may be other enhancements to the Fedwire Funds Service and NSS that could be considered in the context of or in addition to expanded hours. For example, the possibility of a new participant directory feature that potentially provides a listing of participants open for transactions and at which times has been raised by participants. Other potential service enhancements center around further access to information, such as the improved ability for institutions to track payments from sender to beneficiary, and application programming interfaces (APIs) to access payments-related data. In addition, some institutions have raised the possibility of improved fraud controls or screening capabilities. Finally, a significant undertaking could entail the addition of a liquidity savings mechanism for the Fedwire Funds Service.[34] The Board is seeking to understand such functionality considerations and others, including the priority institutions place on their development, particularly in relation to expanding operating hours.

D. Availability of the Discount Window

The Board recognizes banks' ability to access funding during expanded weekend and holiday hours will be important and seeks comments on the need for discount window operations to support expanded hours.[35] The Board stated in its 2019 notice related to the development of the FedNow Service that the Federal Reserve would conduct analysis on extending discount window operations to make overnight credit available on weekends and holidays. Subsequently, in its 2020 notice announcing the details of the FedNow Service, the Board noted that the need for overnight credit on weekend and holidays was expected to be limited initially, and the hours during which discount window loans could be originated would remain unchanged.[36] This perspective was influenced by the expected low volumes for a new service as well as by the lower dollar value of FedNow Service transactions.

The Board recognizes that the combination of the FedNow Service maturing in the coming years and the Board's proposal to expand Fedwire Funds Service and NSS operating hours, with limits of one penny less than $10 billion per payment order and one penny less than $10 trillion per settlement file, respectively, will increase the importance of accessing liquidity on weekends and holidays. The Board is seeking comment on the potential demand for liquidity via the discount window during expanded hours for the Fedwire Funds Service and NSS and whether its availability during certain defined hours on weekends and holidays would affect industry views on expanded hours.

IV. Expanded Hours Impact on the Payment System Risk Policy (PSR Policy)

Part II of the PSR policy governs the provision of intraday credit (also known as daylight overdrafts) to institutions with accounts at the Reserve Banks and outlines the methods that Reserve Banks use to control credit risk associated with providing intraday credit.[37] Intraday credit supports the smooth functioning of the payment system by supplying temporary liquidity in order to cover shortages in institutions' account that can result when the timing of payment inflows and outflows are not balanced. To be eligible for intraday credit, the PSR policy requires that an institution be ''financially healthy'' and have regular access to the discount window. Reserve Banks monitor financial and supervisory developments to determine an institution's eligibility for intraday credit and have several tools to control credit risk to Reserve Banks, including caps on intraday credit, incentivizing or in some cases requiring collateral, and the ability to monitor the institution's account balance in real time and reject Fedwire Funds Service or NSS transactions.

The PSR policy allows for access to intraday credit up to 24x7x365. Therefore, if the Federal Reserve expands the operating hours of the Fedwire Funds Service and NSS, those institutions eligible to access intraday credit and electing to use the services would have access to intraday credit during the expanded hours. Reserve

private-sector clearing arrangement. Settlers must have their own master account.

[32] *See* 12 CFR part 210, app. A, § 4A–106, 4A–302(a)(1), 4A–404.

[33] However, participants face this same challenge in the current operating environment of the Fedwire Funds Service and NSS, which provides similar optionality in participation.

[34] A liquidity savings mechanism can be defined as a queuing arrangement for payments, which conditions the release of queued payments on the receipt of offsetting or partially offsetting payments, and as a result economizes on the use of participants' cash balances.

[35] Discount window office hours vary by district, but typically begin at 8:00 or 8:30 a.m. local time and end when the Fedwire Funds Service closes at 7:00 p.m. ET.

[36] *See* 85 FR 48522 (August 11, 2020) Liquidity management transfer functionality was included as a core part of the FedNow Service at the time of its launch.

[37] The PSR policy is available at *https://www.federalreserve.gov/paymentsystems/psr_about.htm.*

Banks would continue to use the same general framework to monitor institutions and control credit risk as they use in the current operating environment. Further, if the Federal Reserve expands Fedwire Funds Service and NSS hours, the Board would continue to expect that institutions manage their master accounts in compliance with the Board's Payment System Risk Policy and other Federal Reserve policies, including to avoid overnight overdrafts.[38]

If the Board finalizes this proposal to expand operating hours for the Fedwire Funds Service and NSS, it would also make any necessary updates to existing policies as well, including the PSR policy.

V. Exclusion of the Fedwire Securities Service

At this time, the Board is not considering expanding operating hours for the Fedwire Securities Service.[39] The Board does not expect the proposed expansion of Fedwire Funds Service and NSS operating hours to create significant changes in secured lending, derivatives markets, or other market activity that would necessitate expanded operating hours for the Fedwire Securities Service in the near term. In part, this is because the aggregate value of transfers during current off-hours for the large-value payment services will likely be relatively low at the outset and thus unlikely to result in increased demand for securities transfers during those hours. It is possible that expanded hours for the Fedwire Funds Service and NSS could influence markets in the longer-term, which could in turn increase demand for the Fedwire Securities Service during current off-hours.

The Board understands that expanding operating hours for the Fedwire Securities Service will require greater study and coordination with other FMUs, services, and institutions that are typically open alongside the service, such as securities pricing services and repurchase agreement service providers. The Board will continue to monitor activity in securities markets and seek feedback from institutions to determine whether to pursue in the future an expansion of Fedwire Securities Service operating hours.

VI. Competitive Impact Analysis

Board policy requires that the Board conduct a competitive impact analysis when considering changes to a service. The policy requires the Board to first determine whether there will be a direct and material adverse effect on the ability of other service providers to compete effectively with the Federal Reserve in providing similar services and then, if such an adverse effect is identified, to determine if that effect is due to differing legal powers or the Federal Reserve's dominant market position deriving from such legal differences. Next, if such legal differences exist, then the proposed change would be further evaluated to assess its benefits and the proposal could be modified.[40]

The Board believes that an expansion of Fedwire Funds Service and NSS operating hours would not have a direct and material adverse effect on the ability of other service providers to compete effectively with the Federal Reserve. In particular, the Federal Reserve provides the only large-value payment services in the United States that allow settlement in central bank money. The main private-sector provider of large-value payment services and a number of depository institutions offered comments on a previous **Federal Register** notice noting that they would benefit from an expansion of Fedwire Funds Service operating hours.[41] These organizations indicated that an expansion of Fedwire Funds Service operating hours would improve efficiency and reduce risk in conducting U.S. dollar payments and settlements and would support private-sector payments efforts in the United States. For instance, expanding Fedwire Funds Service operating hours could improve liquidity risk management for payment systems that rely on the Fedwire Funds Service for prefunding (for example, a private-sector instant payment service, a large-value payment service, and a foreign exchange settlement system). Accordingly, an expansion of Fedwire Funds Service and NSS operating hours is not expected to adversely impact any other service provider that competes with Federal Reserve payment services and could instead support their efficiency and resilience.

VII. Request for Comment

The Board requests public comment on the entire proposal, and specifically on the following questions:

1. What are the primary benefits to the banking industry, financial markets, and broader economy from an expansion to 22x7x365 Fedwire Funds Service and NSS operating hours? What are the primary benefits to your institution?

2. What will be the primary sources of demand for expanded hours for the Fedwire Funds Service and NSS, from 22x5 to 22x7x365? What types of transactions or institutions are most likely to generate demand for the ability to make payments during weekend hours? What additional use cases could be satisfied with the expansion to full 24x7x365 operating hours? Would they represent sources of new and additional volume that could flow over the Fedwire Funds Service, a shift of

[38] To minimize Reserve Bank exposure to overnight overdrafts, the Board charges a penalty fee to discourage institutions from incurring overnight overdrafts. See part III of the PSR policy. An institution would incur an overnight overdraft on each calendar day that its account balance is negative at 7:00 p.m. ET, which is the close of the business day. All institutions, regardless of the Reserve Bank payment services that they use, will incur an overnight overdraft penalty charge for each calendar day, including weekends and holidays, that an overnight overdraft is outstanding.

[39] The Fedwire Securities Service is currently open for transfers between participants from 8:30 a.m. ET until 3:30 p.m. ET Monday through Friday, excluding holidays observed by the Reserve Banks. In addition, Fedwire Securities Service participants may reposition securities between their own securities accounts from 8:30 a.m. ET until 7:00 p.m. ET on those same weekdays.

[40] *See* The Federal Reserve in the Payments System (issued 1984; revised 1990), Federal Reserve Regulatory Service 9–1558. The policy states, ''The Board will also conduct a competitive impact analysis when considering an operational or legal change, such as a change to a price or service, or a change to Regulation J, if that change would have a direct and material adverse effect on the ability of other service providers to compete effectively with the Federal Reserve in providing similar services due to differing legal powers or constraints or due to a dominant market position of the Federal Reserve deriving from such legal differences. All operational or legal changes having a substantial effect on payments-system participants will be subject to a competitive-impact analysis, even if competitive effects are not apparent on the face of the proposal. In conducting the competitive-impact analysis, the Board would first determine whether the proposal has a direct and material adverse effect on the ability of other service providers to compete effectively with the Federal Reserve in providing similar services. Second, if such an adverse effect on the ability to compete is identified, the Board would then ascertain whether the adverse effect was due to legal differences or due to a dominant market position deriving from such legal differences. Third, if it is determined that legal differences or a dominant market position deriving from such legal differences exist, then the proposed change would be further evaluated to assess its benefits, such as contributing to payments-system efficiency or integrity or other Board objectives, and to determine whether the proposal's objectives could be reasonably achieved with a lesser or no adverse competitive impact. Fourth, the Board would then either modify the proposal to lessen or eliminate the adverse impact on competitors' ability to compete or determine that the payments-system objectives may not be reasonably achieved if the proposal were modified. If reasonable modifications would not mitigate the adverse effect, the Board would then determine whether the anticipated benefits were significant enough to proceed with the change even though it may adversely affect the ability of other service providers to compete with the Federal Reserve in that service.''

[41] *See* comment letters submitted to the ''Potential Federal Reserve Actions to Support Interbank Settlement of Faster Payments, Request for Comment,'' 83 FR 57351.

existing volume over the service, or both?

3. How might expanded operating hours of the Fedwire Funds Service and NSS support private-sector innovation?

4. How does the existence of the FedNow Service affect your views of the benefits of expanded hours for the Fedwire Funds Service and NSS? How do you anticipate using these services in the future?

5. Do you prefer an interim expansion of operating hours before moving to 22x7x365? If so, what operating hours for the Fedwire Funds Service and NSS would be most useful for your institution? What considerations factor into your preference?

6. What is your preferred timeline for a potential expansion of Fedwire Funds Service and NSS operating hours to 22x7x365? What considerations factor into your preference (for example, demand, time to implement changes, adjustments to staffing and internal systems, other major industry milestones or payment system improvements)?

7. Are you interested in full 24x7x365 operating hours for Fedwire Funds Service and NSS? If so, what is your preferred time frame for such an expansion of operating hours? What considerations factor into your preference?

8. What costs and risks would arise for the banking industry, financial markets, and broader economy from an expansion to 22x7x365 of Fedwire Funds Service and NSS operating hours? What are the costs and risks to your institution? What is the estimated incremental cost on a percentage basis to support 22x7x365 operating hours for the Fedwire Funds Service and NSS? What are the implications for competitiveness?

9. What are the ways in which benefits, costs, or risks of 22x7x365 Fedwire Funds Service and NSS could vary for different types of market participants (for example, for smaller institutions, non-traditional participants, or participants in particular time zones)?

10. Are there infrastructure-related market conditions or barriers (for example, the availability of short-term funding markets over the weekend) that may prevent or reduce your firm's ability to fully achieve the potential benefits of 22x7x365 operating hours for the Fedwire Funds Service and NSS? If so, what are they? What steps might the industry and/or Federal Reserve take to remove such barriers?

11. The Federal Reserve plans to maintain the ability to opt out of expanded hours. How would the optionality with respect to participating in a 22x7x365 operating hours environment of the Fedwire Funds Service and NSS, as described in this notice, benefit or challenge your institution or the broader industry? What steps might the Federal Reserve take to augment potential benefits? What steps might the Federal Reserve take to mitigate potential costs and risks?

12. How does your institution anticipate managing liquidity needs in an expanded hours environment? Is the availability of discount window loan originations on weekends and holidays a prerequisite for expanded operating hours for the Fedwire Funds Service and NSS? If so, should the discount window be available 22x7x365, or alternatively, during certain defined hours on weekends and holidays? During what hours should discount window loan originations be available?

13. What effects, if any, on funding market activity should be taken into account when considering the expansion of operating hours for the Fedwire Funds Service and NSS? Would the expansion of operating hours for the Fedwire Funds Service and NSS affect existing wholesale funding markets, including the repurchase market? Do you expect wholesale funding market activity to occur on weekends and holidays?

14. Describe any other enhancements or initiatives that the Reserve Banks should consider in addition to, or in the context of, expanded hours for the Fedwire Funds Service and NSS. How would such potential enhancements be used in the context of expanded hours? Are there any potential service enhancements that should be prioritized ahead of expanded hours?

15. Please describe any other consideration that you believe should be taken into account as the Board contemplates expansion of operating hours for the Fedwire Funds Service and NSS.

By order of the Board of Governors of the Federal Reserve System.

Ann E. Misback,

Secretary of the Board.

[FR Doc. 2024–10117 Filed 5–8–24; 8:45 am]

BILLING CODE 6210–01–P

GENERAL SERVICES ADMINISTRATION

[Notice–IEB–2024–05; Docket No. 2024–0002; Sequence No. 23]

Privacy Act of 1974; System of Records

AGENCY: General Services Administration (GSA).

ACTION: Notice of a modified system of records.

SUMMARY: GSA proposes to modify a system of records subject to the Privacy Act of 1974, as amended. The system of records was established to collect and maintain records needed by the Office of Inspections to carry out its responsibilities pursuant to the Inspector General Act of 1978, as amended. The Office of Inspector General (OIG) is statutorily directed to provide leadership and coordination and recommend policies for activities relating to programs and operations of the General Services Administration, to promote economy, efficiency, and effectiveness in the administration of such programs and operations, and to prevent and detect fraud, waste, and abuse in such programs and operations. Accordingly, the records in this system are used in the course of inspections and evaluations, and other special projects as determined by the Inspector General. The previously published notice is being revised to add four new routine uses and make changes to update the System Of Records Notice (SORN).

DATES: Submit comments on or before June 10, 2024.

ADDRESSES: Comments may be submitted to the Federal eRulemaking Portal, *http://www.regulations.gov.* Submit comments by searching for GSA/ADM–25, Inspection Case Files.

FOR FURTHER INFORMATION CONTACT: Call or email Richard Speidel, Chief Privacy Officer at 202–969–5830 and *gsa.privacyact@gsa.gov.*

SUPPLEMENTARY INFORMATION: GSA proposes to modify a system of records subject to the Privacy Act of 1974, 5 U.S.C. 552a. GSA intends to add four new routine uses that are consistent with the purposes of this system of records.

GSA proposes adding a routine use (routine use ''o'') and revising routine use ''p'' to reflect the current Office of Management and Budget (OMB) breach response guidance in M–17–12, Preparing for and Responding to a Breach of Personally Identifiable Information.

The Inspector General Empowerment Act of 2016 (IGEA), 5 U.S.C. 406(j), exempts certain computerized data comparisons performed by or in coordination with Inspectors General from the Computer Matching and Privacy Protection Act of 1988, Pub. L. 100–503. GSA proposes adding a new routine use (routine use ''r'') to clarify that the GSA Office of Inspector General (OIG) has authority to compare OIG records contained in the system with the records of other Federal agencies and non-Federal records.

GSA also proposes adding two additional routine uses. The first is a new routine use (routine use ''s'') to permit disclosures to the Office of Personnel Management (OPM), Government Accountability Office (GAO) and the Office of Management and Budget (OMB) in accordance with their responsibilities for evaluating Federal programs. The second is a routine use (routine use ''t'') to allow GSA OIG to disclose pertinent records in any legal proceeding before a court or administrative body where GSA or GSA OIG is a party.

Additionally, GSA is making changes to the SORN to update the information in the SORN. In addition to making minor technical and administrative corrections and changes to format, GSA proposes: (1) updating the system location to include secure servers maintained by third-party secure providers to support the procurement of solutions or processes that may require the support of third-party service providers; (2) changing the name of the system of record; (3) providing a new description of the purpose of the SORN to better summarize the purpose of this system of records; (4) updating the categories of records in the system and the records source categories; (5) adding a section for the categories of individuals covered by the system; (6) updating the location of electronic records, record storage and safeguarding procedures to reflect new technology and procedures used to protect government records; and (7) changing the notification, access, and amendment procedures to align with the corresponding GSA Code of Federal Regulations. The proposed revisions are compatible with the purpose of this system of record.

Richard Speidel,

Chief Privacy Officer,Office of the Deputy Chief Information Officer, General Services Administration.

SYSTEM NAME AND NUMBER:

Inspection Case Files, GSA/ADM–25.

SECURITY CLASSIFICATION:

Unclassified.

SYSTEM LOCATION:

The system is maintained electronically and in paper form at the GSA Office of Inspector General, 1800 F Street NW, Washington, DC 20405. Original and duplicate systems may exist, in whole or in part, at secure sites and on secure servers maintained by third-party service providers for the GSA OIG. These systems are FedRAMP Moderate compliant and have all applicable Federal Information Security Modernization Act (FISMA), Federal Information Processing Standards (FIPS), and security controls as applicable.

SYSTEM MANAGER(S):

Director, Information Technology of the Office of Inspector General, General Services Administration (JPM), 1800 F Street, NW, Washington, DC 20405.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

General authority to maintain the system is contained in the Inspector General Act of 1978, as amended, 5 U.S.C. 401–424.

PURPOSE(S) OF THE SYSTEM:

The OIG maintains this system of records to carry out its responsibilities pursuant to the Inspector General Act of 1978, as amended. The OIG is statutorily directed to provide leadership and coordination and recommend policies for activities relating to programs and operations of the General Services Administration, to promote economy, efficiency, and effectiveness in the administration of such programs and operations, and to prevent and detect fraud, waste, and abuse in such programs and operations. Accordingly, the records in this system are used in the course of inspections and evaluations, and other special projects as determined by the Inspector General.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

The system contains records pertaining to present and former GSA and OIG employees, applicants for employment with GSA and GSA OIG, individuals who have filed a complaint with GSA or GSA OIG, individuals who have provided information to inspections and evaluations, government contractors and employees of government contractors, and individuals referenced in potential or actual cases and matters being examined by the Office of Inspections.

CATEGORIES OF RECORDS IN THE SYSTEM:

Inspection files contain information such as name, date, place of birth, contact information, social security number, experience, work-history, and other material that is used in GSA OIG inspections, evaluations, and operations.

RECORD SOURCE CATEGORIES:

Records are collected from other systems, individuals and their representatives, present and former GSA and OIG employees, witnesses, complainants, other Federal and State agencies, non-Federal entities, data services, employers, references, co-workers, government contractors, educational institutions, and public sources.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND PURPOSES OF SUCH USES:

In addition to other disclosures generally permitted under subsection (b) of the Privacy Act of 1974, 5 U.S.C. 552a(b), the GSA OIG may disclose records for the following routine uses:

a. A record of any case in which there is an indication of a violation or potential violation of law, whether civil, criminal, or regulatory in nature, may be disseminated to the appropriate Federal, State, local, or foreign agency charged with the responsibility for investigating or prosecuting such a violation or charged with enforcing or implementing the law.

b. A record may be disclosed to a Federal, State, local, or foreign agency or to an individual or organization in the course of investigating a potential or actual violation of any law, whether civil, criminal, or regulatory in nature, or during the course of a trial or hearing or the preparing for a trial or hearing for such a violation, if there is reason to believe that such agency, individual, or organization possesses information relating to the investigation, and disclosing the information is reasonably necessary to elicit such information or to obtain the cooperation of a witness or an informant.

c. A record relating to a case or matter may be disclosed in an appropriate Federal, State, local, or foreign court or grand jury proceeding in accordance with established constitutional, substantive, or procedural law or practice, even when the agency is not a party to the litigation.

d. A record relating to a case or matter may be disclosed to an actual or potential party or to his or her attorney for the purpose of negotiation or discussion on matters such as settlement of the case or matter, plea-

bargaining, or informal discovery proceedings.

e. A record relating to a case or matter that has been referred by an agency for investigation, prosecution, or enforcement or that involves a case or matter within the jurisdiction of any agency may be disclosed to the agency to notify it of the status of the case or matter or of any decision or determination that has been made or to make such other inquiries and reports as are necessary during the processing of the case or matter.

f. A record relating to a case or matter may be disclosed to a foreign country pursuant to an international treaty or convention entered into and ratified by the United States, or to an Executive agreement.

g. A record may be disclosed to a Federal, State, local, foreign, or international law enforcement agency to assist in crime prevention and detection or to provide leads for investigation.

h. A record may be disclosed to a Federal, State, local, foreign, Tribal, or other public authority in response to its request in connection with the assignment, hiring or retention of an individual and/or employee, or disciplinary or other administrative action concerning an employee, the issuance or revocation of a security clearance, the reporting of an investigation of an individual and/or employee, or the award of a contract, grant, or other benefit by the requesting agency, to the extent that the information relates to the requesting agency's decision on the matter.

i. A record may be disclosed to news media and the public in order to provide information related to an inspection or evaluation when the Inspector General determines there exists a legitimate public interest, unless the Inspector General determines that release of the specific information in the context of a particular case would constitute an unwarranted invasion of personal privacy.

j. A record may be disclosed to an appeal, grievance, hearing, or complaint examiner; an equal opportunity investigator, arbitrator, or mediator; and/or an exclusive representative or other person authorized to investigate or settle a grievance, complaint, or appeal filed by an individual who is the subject of the record.

k. A record may be disclosed as a routine use to a Member of Congress or to a congressional staff member in response to an inquiry of the congressional office made at the request of the person who is the subject of the record.

l. Information may be disclosed at any stage of the legislative coordination and clearance process to the Office of Management and Budget (OMB) for reviewing private relief legislation as set forth in OMB Circular No. A–19.

m. A record may be disclosed: (a) to an expert, a consultant, or contractor of GSA or GSA OIG engaged in a duty related to an agency function to the extent necessary to perform the function; and (b) to a physician to conduct a fitness-for-duty examination of a GSA or GSA OIG officer or employee.

n. A record may be disclosed to any official charged with the responsibility to conduct qualitative assessment reviews of internal safeguards and management procedures employed in inspection operations. This disclosure category includes members of the Council of the Inspectors General on Integrity and Efficiency and officials and administrative staff within their chain of command, as well as authorized officials of the Department of Justice and the Federal Bureau of Investigation.

o. To appropriate agencies, entities, and persons when (1) GSA and/or GSA OIG suspects or has confirmed that there has been a breach of the system of records; (2) GSA and/or GSA OIG has determined that as a result of the suspected or confirmed breach there is a risk of harm to individuals, GSA and/or GSA OIG (including its information systems, programs, and operations), the Federal Government, or national security; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with GSA's and/or GSA OIG's efforts to respond to the suspected or confirmed breach or to prevent, minimize, or remedy such harm.

p. To another Federal agency or Federal entity, when GSA and/or GSA OIG determines that information from this system of records is reasonably necessary to assist the recipient agency or entity in (1) responding to a suspected or confirmed breach or (2) preventing, minimizing, or remedying the risk of harm to individuals, the recipient agency or entity (including its information systems, programs, and operations), the Federal Government, or national security, resulting from a suspected or confirmed breach.

q. To the National Archives and Records Administration (NARA) for records management purposes.

r. A record may be disclosed to compare such record with records in other Federal agencies' systems of records or to non-Federal records.

s. To the Office of Personnel Management (OPM), the Office of Management and Budget (OMB), and the Government Accountability Office (GAO) in accordance with their responsibilities for evaluating Federal programs.

t. In any legal proceeding, where pertinent, to which GSA or GSA OIG is a party before a court or administrative body.

POLICIES AND PRACTICES FOR STORAGE OF RECORDS:

Electronic records and backups are stored on secure servers and accessed only by authorized personnel, in accordance with GSA OIG IT Security Policy. Paper files are stored in locked rooms or filing cabinets with access limited to authorized personnel.

POLICIES AND PRACTICES FOR RETRIEVAL OF RECORDS:

System records are retrievable by searching for information in the case file, including but not limited to, name of an individual, case name, case number, or social security number.

POLICIES AND PRACTICES FOR RETENTION AND DISPOSAL OF RECORDS:

System records are retained and disposed of according to GSA's records maintenance and disposition schedules and the requirements of the National Archives and Records Administration.

ADMINISTRATIVE, TECHNICAL, AND PHYSICAL SAFEGUARDS:

Records in the system are protected from unauthorized access and misuse through a combination of administrative, technical, and physical security measures. Administrative measures include but are not limited to policies that limit system access to individuals within an agency with a legitimate business need, and regular review of security procedures and best practices to enhance security. Technical measures include but are not limited to system design that allows authorized system users access only to data for which they are responsible per FISMA requirements; required use of strong passwords that are frequently changed; and use of encryption for certain data transfers using current FIPS compliant protocols. Physical security measures include but are not limited to the use of data centers which meet government requirements for storage of sensitive data. Paper files are stored in locked rooms or filing cabinets and can only be accessed by authorized users.

RECORD ACCESS PROCEDURES:

This system of records is exempt from certain notification, access, and

amendment procedures of the Privacy Act, as described below. However, GSA OIG will consider individual requests to determine whether or not information may be released. If an individual wishes to access any record pertaining to him or her in the system, that individual should consult the GSA's Privacy Act implementation rules available at 41 CFR part 105–64.2.

CONTESTING RECORD PROCEDURES:

If an individual wishes to contest the content of any record pertaining to him or her in the system, that individual should consult the GSA's Privacy Act implementation rules available at 41 CFR part 105–64.4.

NOTIFICATION PROCEDURES:

Individuals seeking notification of any records about themselves contained in this system of records should contact the system manager at the address above. Follow the procedures on accessing records in 41 CFR part 105–64, subpart 105–64.2 to request such notification.

EXEMPTIONS PROMULGATED FOR THE SYSTEM:

a. In accordance with 5 U.S.C. 552a(j), this system of records is exempt from all provisions of the Privacy Act of 1974 with the exception of subsections (b); (c)(1) and (2); (e)(4)(A) through (F); (e)(6), (7), (9), (10), and (11); and (i) of the Act, to the extent that information in the system pertains to the enforcement of criminal laws, including police efforts to prevent, control, or reduce crime or to apprehend criminals; to the activities of prosecutors, courts, and correctional, probation, pardon, or parole authorities; and to (a) information compiled for the purpose of identifying individual criminal offenders and alleged offenders and consisting only of identifying data and notations of arrests, the nature and disposition of criminal charges, sentencing, confinement, release, and parole and probation status; (b) information compiled for the purpose of a criminal investigation, including reports of informants and investigators, that is associated with an identifiable individual; or (c) reports of enforcement of the criminal laws, from arrest or indictment through release from supervision. This system is exempted to maintain the efficacy and integrity of the Office of Inspector General's law enforcement function.

In accordance with 5 U.S.C. 552a(k), this system of records is exempt from subsections (c)(3); (d); (e)(1); (e)(4)(G), (H), and (I); and (f) of the Privacy Act of 1974 to the extent that the system consists of investigatory material compiled for law enforcement purposes, other than material within the scope of 5 U.S.C. 552a(j). However, if an individual is denied any right, privilege, or benefit to which the individual would otherwise be eligible as a result of the maintenance of such material, such material shall be provided to such individual, except to the extent that the disclosure of such material would reveal the identity of a source who furnished information to the government under an express promise that the identity of the source would be held in confidence, or, prior to the effective date of the Act, under an implied promise that the identity of the source would be held in confidence; and

b. To the extent the system consists of investigatory material compiled solely for the purpose of determining suitability, eligibility, or qualifications for Federal civilian employment, military service, Federal contracts, or access to classified information, but only to the extent that the disclosure of such material would reveal the identity of a source who furnished information to the government under an express promise that the identity of the source would be held in confidence, or, prior to the effective date of the Act, under an implied promise that the identity of the source would be held in confidence.

This system has been exempted to maintain the efficacy and integrity of lawful investigations conducted pursuant to the Office of Inspector General's law enforcement responsibilities and responsibilities in the areas of Federal employment, government contracts, and access to security classified information.

HISTORY:

This notice revises the previously published notice (73 FR 22383, April 25, 2008).

[FR Doc. 2024–10148 Filed 5–8–24; 8:45 am]

BILLING CODE 6820–AB–P

GENERAL SERVICES ADMINISTRATION

[Notice–IEB–2024–04; Docket No. 2024–0002; Sequence No. 22]

Privacy Act of 1974; System of Records

AGENCY: General Services Administration

ACTION: Notice of a modified system of records.

SUMMARY: GSA proposes to modify a system of records subject to the Privacy Act of 1974, as amended. The previously published notice is being revised to add two new routine uses, make law enforcement records held within the system exempt from the access and amendment provisions of the Privacy Act, and make changes to update the System of Records Notice (SORN).

DATES: Submit comments on or before June 10, 2024.

ADDRESSES: Comments may be submitted to the Federal eRulemaking Portal, *http://www.regulations.gov.* Submit comments by searching for GSA/ADM–26, Office of Inspector General Counsel Files.

FOR FURTHER INFORMATION CONTACT: Call or email Richard Speidel, Chief Privacy Officer at 202–969–5830 and *gsa.privacyact@gsa.gov.*

SUPPLEMENTARY INFORMATION: GSA proposes to modify the SORN for the Office of Inspector General Counsel Files subject to the Privacy Act of 1974, 5 U.S.C. 552a. GSA intends to add two new routine uses that are consistent with the purpose of this system of records.

GSA proposes adding a routine use (routine use ''j'') and revising routine use ''i'' to reflect the current Office of Management and Budget (OMB) breach response guidance in M–17–12, Preparing for and Responding to a Breach of Personally Identifiable Information.

The Inspector General Empowerment Act of 2016 (IGEA), 5 U.S.C. 406(j), exempts certain computerized data comparisons performed by or in coordination with Inspectors General from the Computer Matching and Privacy Protection Act of 1988, Pub. L. 100–503. GSA proposes adding a new routine use (routine use ''n'') to clarify that the GSA Office of Inspector General (OIG) has authority to compare OIG records contained in the system with the records of other Federal agencies and non-Federal records. GSA is also updating the SORN to make law enforcement records contained in the system exempt from the access and amendment provisions of the Privacy Act, consistent with the other two OIG SORNs, which are listed as GSA/ADM–24 and GSA/ADM–25.

In addition to making minor technical and administrative corrections and changes to format, GSA proposes: (1) updating the system location to include secure servers maintained by third-party secure providers to support the procurement of solutions or processes that may require the support of third-party service providers; (2) updating the categories of individuals covered by the system; (3) adding additional detail to the categories of records in the system

and the record source categories; and (4) changing the notification, access, and amendment procedures to align with the corresponding GSA Code of Federal Regulations. The proposed revisions are compatible with the purpose of this system of record.

The Inspector General Act of 1978 (as amended 5 U.S.C. 401–424) established the GSA OIG to conduct and supervise audits and investigations relating to the programs and operations of GSA. Within the GSA OIG, the responsibilities of the Office of Counsel to the Inspector General include (1) providing legal services to the OIG on GSA programs and operations, administrative law issues, and criminal procedure, (2) representing the OIG in assisting the Department of Justice (DOJ) with litigation, including settlement of cases arising under the False Claims Act, (3) representing the OIG in personnel actions, and (4) responding to requests submitted to the OIG, including under the Freedom of Information Act (FOIA) and Privacy Act. The Office of Inspector General Counsel Files provide for the collection of information to track, manage, and process False Claims Act complaints, administrative actions including personnel matters, FOIA and Privacy Act requests, and other administrative and litigation matters handled by the Office of Counsel to the Inspector General.

Richard Speidel,

Chief Privacy Officer,Office of the Deputy Chief Information Officer, General Services Administration.

SYSTEM NAME AND NUMBER:

Office of Inspector General Counsel Files, GSA/ADM–26.

SECURITY CLASSIFICATION:

Unclassified.

SYSTEM LOCATION:

The system is maintained electronically and in paper form in the Office of Counsel to the Inspector General (OIG/JC). Original and duplicate systems may exist, in whole or in part, at secure sites and on secure servers maintained by third-party service providers for the GSA OIG. These systems are FedRAMP Moderate compliant and have all applicable Federal Information Security Modernization Act (FISMA), Federal Information Processing Standards (FIPS), and security controls as applicable.

SYSTEM MANAGER(S):

Director, Information Technology of the Office of Inspector General (JPM), 1800 F Street NW, Washington, DC 20405.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

General authority to maintain the system is contained in the Inspector General Act of 1978, as amended, 5 U.S.C. 401–424.

PURPOSE(S) OF THE SYSTEM:

The records in this system are maintained for the purpose of providing representational and advisory legal services to the OIG.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

The system contains records related to individuals involved in litigation with the United States, or the OIG, officials, or components of the OIG; individuals involved in administrative proceedings before the OIG, to which the OIG is a party or in which the OIG has an interest; individuals suspected of violations of criminal and civil statutes or regulations or GSA policies, procedures, or directives; individuals who have filed a FOIA request, Privacy Act request, or FOIA or Privacy Act appeal; individuals involved in negotiations, claims, or disputes with the OIG; present and former employees of GSA and the OIG; individuals who have submitted a complaint or allegation to the OIG; and individuals referenced in potential or actual cases and matters under the jurisdiction of the Office of Counsel to the Inspector General.

CATEGORIES OF RECORDS IN THE SYSTEM:

The system contains information needed by the Office of Counsel to the Inspector General to represent and advise the OIG. Records in this system pertain to a broad variety of matters under the jurisdiction of the Office of Counsel, including but not limited to civil, criminal, and administrative actions, personnel matters, correspondence, special projects, and FOIA and Privacy Act requests and appeals. Records may include but are not limited to: name, social security number, addresses, phone numbers, email addresses, birth date, financial information, work history, medical records, or employment records. The system may also contain other records such as: case history files, copies of applicable laws, working papers of attorneys, testimony of witnesses, correspondence, accident reports, pleadings, affidavits, litigation reports, financial data, and other material that is used as a basis for providing legal advice.

RECORD SOURCE CATEGORIES:

Records are collected from other systems, individuals and their representatives, present and former GSA and OIG employees, complainants, informants, witnesses, government contractors, law enforcement agencies, other government agencies, State agencies, credit bureaus, data services, employers, references, educational institutions, public sources, and entities involved in an administrative matter, claim or litigation.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND PURPOSES OF SUCH USES:

In addition to other disclosures generally permitted under subsection (b) of the Privacy Act of 1974, 5 U.S.C. 552a(b), the GSA OIG may disclose records for the following routine uses:

a. A record of any case in which there is an indication of a violation or potential violation of law, whether civil, criminal, or regulatory in nature, may be disseminated to the appropriate Federal, State, local, or foreign agency charged with the responsibility for investigating or prosecuting such a violation or charged with enforcing or implementing the law.

b. A record may be disclosed to a Federal, State, local, or foreign agency or to an individual or organization in the course of investigating a potential or actual violation of any law, whether civil, criminal, or regulatory in nature, or during the course of a trial or hearing or the preparation for a trial or hearing for such a violation, if there is reason to believe that such agency, individual, or organization possesses information relating to the investigation, and disclosing the information is reasonably necessary to elicit such information or to obtain the cooperation of a witness or an informant.

c. A record relating to a case or matter may be disclosed in an appropriate Federal, State, local, or foreign court or grand jury proceeding in accordance with established constitutional, substantive, or procedural law or practice, even when the agency is not a party to the litigation.

d. A record relating to a case or matter may be disclosed to an actual or potential party or to his or her attorney for the purpose of negotiation or discussion on matters such as settlement of the case or matter, plea-bargaining, or informal discovery proceedings.

e. A record may be disclosed to a Federal, State, local, foreign, Tribal, or other public authority in response to its request in connection with the assignment, hiring or retention of an

individual and/or employee, or disciplinary or other administrative action concerning an employee, the issuance or revocation of a security clearance, the reporting of an investigation of an individual and/or employee, or the letting of a contract, or the award of a contract, grant, or other benefit by the requesting agency, to the extent that the information relates to the requesting agency's decision on the matter.

f. A record may be disclosed to an appeal, grievance, hearing, or complaint examiner; an equal opportunity investigator, arbitrator, or mediator; and/or an exclusive representative or other person authorized to investigate or settle a grievance, complaint, or appeal filed by an individual who is the subject of the record.

g. A record may be disclosed as a routine use to a Member of Congress or to a congressional staff member in response to an inquiry of the congressional office made at the request of the person who is the subject of the record.

h. A record may be disclosed: (a) to an expert, a consultant, or contractor of GSA or GSA OIG engaged in a duty related to an agency function to the extent necessary to perform the function; and (b) to a physician to conduct a fitness-for-duty examination of a GSA or GSA OIG officer or employee.

i. To appropriate agencies, entities, and persons when (1) GSA and/or GSA OIG suspects or has confirmed that there has been a breach of the system of records; (2) GSA and/or GSA OIG has determined that as a result of the suspected or confirmed breach there is a risk of harm to individuals, GSA and/or GSA OIG (including its information systems, programs, and operations), the Federal Government, or national security; and (3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with GSA's and/or GSA OIG's efforts to respond to the suspected or confirmed breach or to prevent, minimize, or remedy such harm.

j. To another Federal agency or Federal entity, when GSA and/or GSA OIG determines that information from this system of records is reasonably necessary to assist the recipient agency or entity in (1) responding to a suspected or confirmed breach or (2) preventing, minimizing, or remedying the risk of harm to individuals, the recipient agency or entity (including its information systems, programs, and operations), the Federal Government, or national security, resulting from a suspected or confirmed breach.

k. In any legal proceeding, where pertinent, to which GSA, GSA OIG, a GSA employee, a GSA OIG employee, or the United States or other entity of the United States government is a party before a court or administrative body.

l. To the Office of Personnel Management (OPM), the Office of Management and Budget (OMB), and the Government Accountability Office (GAO) in accordance with their responsibilities for evaluating Federal programs.

m. To the National Archives and Records Administration (NARA) for records management purposes.

n. A record may be disclosed to compare such record with records in other Federal agencies' systems of records or to non-Federal records.

POLICIES AND PRACTICES FOR STORAGE OF RECORDS:

Electronic records and backups are stored on secure servers and accessed only by authorized personnel, in accordance with GSA OIG IT Security Policy. Paper files are stored in locked rooms or filing cabinets with access limited to authorized personnel.

POLICIES AND PRACTICES FOR RETRIEVAL OF RECORDS:

System records are retrievable by searching against information in the record pertaining to an individual, key word, case description, file number, or case title.

POLICIES AND PRACTICES FOR RETENTION AND DISPOSAL OF RECORDS:

System records are retained and disposed of according to GSA records maintenance and disposition schedules and the requirements of the National Archives and Records Administration.

ADMINISTRATIVE, TECHNICAL, AND PHYSICAL SAFEGUARDS

Records in the system are protected from unauthorized access and misuse through a combination of administrative, technical, and physical security measures. Administrative measures include but are not limited to policies that limit system access to individuals within an agency with a legitimate business need, and regular review of security procedures and best practices to enhance security. Technical measures include but are not limited to system design that allows authorized system users access only to data for which they are responsible per FISMA requirements; required use of strong passwords that are frequently changed; and use of encryption for certain data transfers using current FIPS compliant protocols. Physical security measures include but are not limited to the use of data centers which meet government requirements for storage of sensitive data. Paper files are stored in locked rooms or filing cabinets and can only be accessed by authorized users.

RECORD ACCESS PROCEDURES:

This system of records is exempt from certain notification, access, and amendment procedures of the Privacy Act, as described below. However, GSA OIG will consider individual requests to determine whether or not information may be released. If an individual wishes to access any record pertaining to him or her in the system, that individual should consult the GSA's Privacy Act implementation rules available at 41 CFR part 105–64.2.

CONTESTING RECORD PROCEDURES:

If an individual wishes to contest the content of any record pertaining to him or her in the system, that individual should consult the GSA's Privacy Act implementation rules available at 41 CFR part 105–64.4.

NOTIFICATION PROCEDURES:

Individuals seeking notification of any records about themselves contained in this system of records should contact the system manager at the address above. Follow the procedures on accessing records in 41 CFR part 105–64, subpart 105–64.2 to request such notification.

EXEMPTIONS PROMULGATED FOR THE SYSTEM:

a. In accordance with 5 U.S.C. 552a(j), this system of records is exempt from all provisions of the Privacy Act of 1974 with the exception of subsections (b); (c)(1) and (2); (e)(4)(A) through (F); (e)(6), (7), (9), (10), and (11); and (i) of the Act, to the extent that information in the system pertains to the enforcement of criminal laws, including police efforts to prevent, control, or reduce crime or to apprehend criminals; to the activities of prosecutors, courts, and correctional, probation, pardon, or parole authorities; and to (a) information compiled for the purpose of identifying individual criminal offenders and alleged offenders and consisting only of identifying data and notations of arrests, the nature and disposition of criminal charges, sentencing, confinement, release, and parole and probation status; (b) information compiled for the purpose of a criminal investigation, including reports of informants and investigators, that is associated with an identifiable individual; or (c) reports of enforcement of the criminal laws, from arrest or indictment through release from supervision. This system is exempted to

maintain the efficacy and integrity of the Office of Inspector General's law enforcement function.

In accordance with 5 U.S.C. 552a(k), this system of records is exempt from subsections (c)(3); (d); (e)(1); (e)(4)(G), (H), and (I); and (f) of the Privacy Act of 1974 to the extent that the system consists of investigatory material compiled for law enforcement purposes, other than material within the scope of 5 U.S.C. 552a(j). However, if an individual is denied any right, privilege, or benefit to which the individual would otherwise be eligible as a result of the maintenance of such material, such material shall be provided to such individual, except to the extent that the disclosure of such material would reveal the identity of a source who furnished information to the government under an express promise that the identity of the source would be held in confidence, or, prior to the effective date of the Act, under an implied promise that the identity of the source would be held in confidence; and

b. To the extent the system consists of investigatory material compiled solely for the purpose of determining suitability, eligibility, or qualifications for Federal civilian employment, military service, Federal contracts, or access to classified information, but only to the extent that the disclosure of such material would reveal the identity of a source who furnished information to the government under an express promise that the identity of the source would be held in confidence, or, prior to the effective date of the Act, under an implied promise that the identity of the source would be held in confidence.

This system has been exempted to maintain the efficacy and integrity of lawful investigations conducted pursuant to the Office of Inspector General's law enforcement responsibilities and responsibilities in the areas of Federal employment, government contracts, and access to security classified information.

HISTORY:

This notice revises the previously published notice (76 FR 56763, September 14, 2011).

[FR Doc. 2024–10147 Filed 5–8–24; 8:45 am]

BILLING CODE 6820–AB–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Administration for Community Living

Availability of Program Application Instructions for MIPPA Program Funds

AGENCY: Administration for Community Living, HHS.

ACTION: Notice.

Title: Medicare Improvements for Patients and Providers Act: State Applications for Medicare Low-Income Benefit Programs Enrollment Outreach and Assistance.

Announcement Type: Initial.

Statutory Authority: 42 U.S.C. 1395b–3 note.

Catalog of Federal Domestic Assistance (CFDA) Number: 93.071.

DATES: The deadline date for the submission of MIPPA Program State Plans is 11:59 p.m. (ET) on July 8, 2024.

SUPPLEMENTARY INFORMATION:

Funding Opportunity Description

The Medicare Improvement for Patients and Providers Act (MIPPA) program supports states and tribes through grants to provide outreach and assistance to Medicare beneficiaries with limited incomes and assets. MIPPA state grantees help educate beneficiaries about the Low-Income Subsidy (LIS) program for Medicare Part D, Medicare Savings Programs (MSPs), and Medicare Preventive Services while also providing one-on-one assistance to eligible Medicare beneficiaries to help them apply for benefit programs that help lower the costs of their Medicare premiums and deductibles. These funds will allow agencies to provide enhanced outreach to eligible Medicare beneficiaries regarding their preventive, wellness, and limited income benefits; application assistance to individuals who may be eligible for LIS or MSPs; and outreach activities aimed at preventing disease and promoting wellness.

Applicant plans should go above and beyond those regular activities planned in response to other funding sources. ACL will accept only one application for each Priority Area per state. If an agency is eligible for more than one MIPPA Priority Area, the agency may combine their responses into one comprehensive application.

Eligibility Criteria and Other Requirements. MIPPA state funding is limited to state agencies by Priority Area:

- *Priority Area 1—State Health Insurance Assistance Program (SHIP):* SHIP grant recipients or (SHIP-designated state agencies)
- *Priority Area 2—Area Agencies on Aging (AAAs):* State Units on Aging (SUA) (or SUA-designated state agencies)
- *Priority Area 3—Aging and Disability Resource Centers (ADRCs):* Agencies that are established ADRCs (or designated state agency serving as the No Wrong Door lead)

I. Award Information

1. Funding Instrument Type

These awards will be made in the form of cooperative agreements to agencies for each MIPPA Priority Area:

Priority Area 1—SHIP: Grants to state agencies (State Units on Aging or State Departments of Insurance) that administer the SHIP to provide enhanced outreach to eligible Medicare beneficiaries regarding their preventive, wellness, and limited income benefits; application assistance to individuals who may be eligible for LIS or MSPs; and outreach activities aimed at preventing disease and promoting wellness.

Priority Area 2—AAA: Grants to state agencies for AAA programs to provide enhanced outreach to eligible Medicare beneficiaries regarding their preventive, wellness, and limited income benefits; application assistance to individuals who may be eligible for LIS or MSPs; and outreach activities aimed at preventing disease and promoting wellness.

Priority Area 3—ADRC: Aging and Disability Resource Center Programs (ADRC): Grants to agencies that are established ADRCs to provide outreach regarding Medicare Part D benefits related to LIS and MSPs and conduct outreach activities aimed at preventing disease and promoting wellness.

2. Anticipated Total Priority Area Funding

ACL intends to make available, under this program announcement, grant awards for the three MIPPA Priority Areas. Funding will be distributed through a formula as identified in statute. ACL will fund total project periods of up to one year contingent upon availability of federal funds.

- *Priority Area 1—SHIP:* $16.5 million in FY 2024
- *Priority Area 2—AAA:* $17.9 million in FY 2024
- *Priority Area 3—ADRC:* $9.8 million in FY 2024

II. Eligibility Criteria and Other Requirements

1. Eligible entities for this award are state agencies that administer the following:

• *Priority Area 1—SHIP:* Only existing SHIP grant recipients or (SHIP-designated state agencies) are eligible to apply.

• *Priority Area 2—AAA:* Only State Units on Aging (SUA) (or SUA-designated state agencies) are eligible to apply.

• *Priority Area 3—ADRC:* Only agencies that are established ADRCs (or designated state agency serving as the No Wrong Door lead) are eligible to apply.

Eligibility may change if future funding is available.

2. No Match or Cost Sharing is required.

3. Unique Entry ID Number

Unique Entity ID: All grant applicants must obtain and keep current a Unique Entity ID (UEI). On April 4, 2022, the unique entity identifier used across the federal government changed from the DUNS Number to the Unique Entity ID (generated by *SAM.gov*). The Unique Entity ID is a 12-character alphanumeric ID assigned to an entity by *SAM.gov*. The UEI is viewable in your *SAM.gov* entity registration record.

4. Intergovernmental Review

Executive Order 12372, Intergovernmental Review of Federal Programs, is not applicable to these grant applications.

III. Submission Information

1. Application Kit/Program Instructions are available at *www.grantsolutions.gov.* Instructions for completing the application kit will be available on the site.

2. Submission Dates and Times.

To receive consideration, applications must be submitted by 11:59 p.m. (ET) on July 8, 2024, through *www.GrantSolutions.gov.*

IV. Agency Contact

Direct inquiries regarding programmatic issues to: Margaret Flowers, Phone: 202.795.7315, Email: *Margaret.Flowers@acl.hhs.gov.*

Dated: May 5, 2024.

Alison Barkoff,

Principal Deputy Administrator for the Administration for Community Living, performing the delegable duties of the Administrator and the Assistant Secretary for Aging.

[FR Doc. 2024–10126 Filed 5–8–24; 8:45 am]

BILLING CODE 4154–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Administration for Community Living

Announcing the Intent To Award a Single-Source Supplement for the National Falls Prevention Resource Center

AGENCY: Administration for Community Living. HHS.

ACTION: Notice.

SUMMARY: The Administration for Community Living (ACL) announces the intent to award a single-source supplement to the current cooperative agreement held by the National Council on Aging (NCOA) for the National Falls Prevention Resource Center. The purpose of this program is to advance the development and expansion of technical assistance, education, and resources to increase public awareness about the risk of falls and how to prevent them; increase the number of older adults and adults with disabilities who participate in evidence-based community falls prevention programs; and support the integration and sustainability of evidence-based falls prevention programs within community integrated health networks.

DATES: The period of performance for this award will be August 1, 2021, to July 31, 2026.

FOR FURTHER INFORMATION CONTACT: For further information or comments regarding this program supplement, contact Donna Bethge, U.S. Department of Health and Human Services, Administration for Community Living, Administration on Aging, Office of Nutrition and Health Promotion Programs, 202–795–7659, email *donna.bethge@acl.hhs.gov.*

SUPPLEMENTARY INFORMATION: The purpose of this supplement is to:

• provide further development of leaders in the falls prevention network through continuation of the fellowship program to focus on systems change to reduce falls, falls risk factors, and fall related injuries to ultimately improve the lives of older adults and save health care dollars; and

• augment innovative falls prevention projects that cultivate and leverage collaborations with traditional and new partners to address one or more of the recommendations included in the National Falls Prevention Action Plan that will be updated as a result of the National Falls Prevention Summit in September 2024.

The administrative supplement for FY 2024 will be in the amount of $440,402, bringing the total award for FY 2024 to $1,440,402.

The additional funding will not be used to begin new projects, but it will be used to enhance existing efforts. The grantee will continue to provide appropriate, quality falls prevention resources, increase public awareness about falls prevention and the risk of falls, support the implementation of evidence-based falls prevention programs, and seek new opportunities to embed falls prevention evidence-based programs in the community.

Program Name: National Falls Prevention Resource Center.

Recipient: National Council on Aging (NCOA).

Period of Performance: The supplement award will be issued for the fourth year of a five-year project period of August 1, 2021, to July 31, 2026.

Total Award Amount: $1,440,402 in FY 2024.

Award Type: Cooperative Agreement Supplement.

Basis for Award: National Council on Aging (NCOA) is currently funded to carry out the objectives of this project through its current cooperative agreement entitled, National Falls Prevention Resource Center for the period of August 1, 2021, through July 31, 2026. Since the project's implementation, the grantee has made satisfactory progress toward its approved work plan. The supplement will enable the grantee to carry their work even further, enhancing the support they provide to the Aging Network Falls Prevention Providers. The additional funding will not be used to begin new projects or activities, but rather to enhance efforts.

NCOA is uniquely positioned to complete the work called for under this project. They have an already established infrastructure and are a known and trusted organization in the Aging Network. Prior to this current award, NCOA competed and was twice awarded the National Falls Prevention Resource Center for the past eight (8) years. They have an established presence within the Aging Network. They have a comprehensive, interactive web-based repository (*https://ncoa.org/professionals/health/center-for-healthy-aging/national-falls-prevention-resource-center*) with tools and resources, including—best practices tip sheets, program and fidelity guidance, Falls Prevention Awareness Week toolkit, educational webinars, Grand Rounds recordings, articles covering topics from program implementation through sustainability, resource hubs, policy and practice models, the Falls Free Checkup online screening tool and

they maintain the national falls prevention database. Under this current award period, they are providing technical assistance and educational opportunities for the Aging Network's Falls Prevention efforts, including workgroups, webinars, and live trainings. They collaborate nationally with state falls prevention collaboratives and host the annual Age + Action Conference, a grantee gathering to explore solutions to ensure equitable aging for all, connecting with colleagues, sharing innovative ideas, and discussing policy solutions that can be achieved together on behalf of older adults. They have reached thousands of providers using their comprehensive database of SUAs, AAAs, and other Falls Prevention Program stakeholders. In addition, they have developed partnerships with organizations, universities, and other entities to provide technical assistance, education, and support for the Aging Network.

Establishing an entirely new grant project at this time would be potentially disruptive to the current work already well under way. More importantly, it could cause confusion among the Aging Network Falls Prevention Program Providers and stakeholders, which could have a negative effect on training, implementation, and support opportunities. If this supplement were not provided, the project would be unable to address the significant unmet needs of the Aging Network Falls Prevention Program.

Statutory Authority: The Older Americans Act of 1965, section 411, as amended (42 U.S.C. 3032); and the Patient Protection and Affordable Care Act, 42 U.S.C. 300u–11.

Dated: May 6, 2024.

Allison Barkoff,

Principal Deputy Administrator for the Administration for Community Living, performing the delegable duties of the Administrator and the Assistant Secretary for Aging.

[FR Doc. 2024–10142 Filed 5–8–24; 8:45 am]

BILLING CODE 4154–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Neurological Disorders and Stroke; Notice of Closed Meetings

Pursuant to section 1009 of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Neurological Disorders and Stroke Initial Review Group; Neurological Sciences and Disorders D Study Section BRAIN Review New Technologies and Optimization (NSD–D).

Date: May 30–31, 2024.

Time: 9:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Canopy by Hilton, 940 Rose Avenue, North Bethesda, MD 20852.

Contact Person: Mir Ahamed Hossain, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Activities, NINDS/NIH/DHHS, NSC, 6001 Executive Blvd., Rockville, MD 20852, 301–496–9223, *mirahamed.hossain@nih.gov*.

Name of Committee: National Institute of Neurological Disorders and Stroke Special Emphasis Panel; NSD–D Member Conflict Review Meeting.

Date: May 31, 2024.

Time: 2:00 p.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852.

Contact Person: Bo-Shiun Chen, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Activities, NINDS/NIH/DHHS, NSC, 6001 Executive Blvd., Rockville, MD 20852, 301–496–9223, *bo-shiun.chen@nih.gov*.

Name of Committee: Neurological Sciences Training Initial Review Group; Neurological Sciences Training 3 Study Section NST–3.

Date: June 6–7, 2024.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852.

Contact Person: Lataisia Cherie Jones, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Activities, NINDS/NIH/DHHS, 6001 Executive Blvd., Rockville, MD 20852, 301–496–9223, *lataisia.jones@nih.gov*.

Name of Committee: National Institute of Neurological Disorders and Stroke Special Emphasis Panel; HEAL Initiative: Team Based Science.

Date: June 7, 2024.

Time: 9:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852.

Contact Person: Abhignya Subedi, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Activities, NINDS/NIH/DHHS, NSC, 6001 Executive Blvd., Rockville, MD 20852, 301–496–9223, *abhi.subedi@nih.gov*.

Name of Committee: National Institute of Neurological Disorders and Stroke Special Emphasis Panel; NIH Blueprint and BRAIN Initiative ENDURE Program.

Date: July 31, 2024.

Time: 10:00 a.m. to 2:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852.

Contact Person: Lataisia Cherie Jones, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Activities, NINDS/NIH/DHHS, NSC, 6001 Executive Blvd., Rockville, MD 20852, 301–496–9223, *lataisia.jones@nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.853, Clinical Research Related to Neurological Disorders; 93.854, Biological Basis Research in the Neurosciences, National Institutes of Health, HHS)

Dated: May 3, 2024.

Lauren A. Fleck,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2024–10092 Filed 5–8–24; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Notice To Announce the Significant Changes to the NIH Grants Policy Statement for Fiscal Year 2024

AGENCY: National Institutes of Health, HHS.

ACTION: Notice.

SUMMARY: The National Institutes of Health (NIH) announces publication of the updated significant changes that have already been made to the NIH Grants Policy Statement (GPS) in fiscal year 2023 that will be reflected in the GPS for fiscal year 2024. The NIH GPS provides both up-to-date policy guidance that serves as NIH standard terms and conditions of award for all NIH grants and cooperative agreements, and extensive guidance to those who are interested in pursuing NIH grants. This update incorporates significant changes for FY 2024, such as new and modified requirements, clarifies certain policies, and implements changes in statutes, regulations, and policies that have been implemented through appropriate legal

and/or policy processes (*e.g.,* **Federal Register** Notices, where appropriate) since the previous version of the NIHGPS dated December 2022.

DATES: The significant changes to the revised NIH GPS for Fiscal Year 2024 is now available for viewing.

ADDRESSES: Please visit our website to view the updated Significant Changes for Fiscal Year 2024 and NIH GPS at *https://grants.nih.gov/policy/nihgps/index.htm.*

FOR FURTHER INFORMATION CONTACT: Xanthia James, Director, Division of Grants Policy, Office of Policy for Extramural Research Administration, NIH, Rockledge I, Suite 350, Bethesda, MD 20817. Email: *Xanthia.James@nih.gov.* Phone number: (301) 435–0949.

SUPPLEMENTARY INFORMATION: This update is applicable to all NIH grants and cooperative agreements with budget periods beginning on or after October 1, 2023. This update supersedes, in its entirety, the NIH GPS dated December 2022. Previous versions of the NIH GPS remain applicable as standard terms and conditions of award for all NIH grants and cooperative agreements with budget periods that began prior to October 1, 2023. This update incorporates new and modified requirements, clarifies certain policies, and implements changes in statutes, regulations, and policies that have been implemented through appropriate legal and/or policy processes since the previous version of the NIH GPS dated December 2022. The current version of the NIH GPS, in both HTML and PDF formats, as well as previous versions of the NIH GPS and documents summarizing significant changes implemented with each revision, are available at *https://grants.nih.gov/policy/nihgps/index.htm.*

As noted in NOT–OD–24–069 *https://grants.nih.gov/grants/guide/notice-files/NOT-OD-24-069.html,* the Office of Management and Budget (OMB) has issued updates to 2 CFR part 200, with an implementation date of October 1, 2024. NIH will include the changes to 2 CFR part 200 in the FY 2025 release of the NIH GPS, in line with the implementation date set by OMB.

Dated: May 1, 2024.

Lawrence Tabak,

Principal Deputy Director, National Institutes of Health.

[FR Doc. 2024–10135 Filed 5–8–24; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Division of Program Coordination, Planning, and Strategic Initiatives, Office of the Director Notice of Proposed Reorganization

AGENCY: National Institutes of Health, HHS.

ACTION: Notice.

SUMMARY: The Division of Program Coordination, Planning, and Strategic Initiatives (DPCPSI) in the Office of the Director, National Institutes of Health (NIH) is seeking public comment regarding its proposal to transfer the *All of Us* (ALL) Research Program and Environmental influences on Child Health Outcomes (ECHO) Program from the Immediate Office of the NIH Director to DPCPSI in the Office of the Director, NIH. The program offices in DPCPSI share a common mission of identifying emerging scientific opportunities, rising public health challenges, or scientific knowledge gaps that deserve special emphasis. The proposed reorganization would align the important offices with offices having similar NIH-wide functions.

DATES: Any interested person may file written comments by sending an email to *DPCPSIreorgcomments@nih.gov* by 11:59 p.m. ET on June 14, 2024. The statement should include the individual's name, and when applicable, professional affiliation.

ADDRESSES: The following email address has been established for comments on the reorganization: *DPCPSIreorgcomments@nih.gov.*

FOR FURTHER INFORMATION CONTACT: Betina Orezzoli at *DPCPSIreorgcomments@nih.gov* or 301–402–9852.

SUPPLEMENTARY INFORMATION: This notice is pursuant to the NIH Reform Act of 2006 (42 U.S.C.281 (d)(4)), DPCPSI will launch public website information at *https://dpcpsi.nih.gov/proposed-reorg-allofus-echo-transfer* to further encourage public discussion of the proposal to reorganize. The public is encouraged to email *DPCPSIreorgcomments@nih.gov* for comments and questions.

Dated: May 3, 2024.

Lawrence A. Tabak,

Principal Deputy Director, National Institutes of Health.

[FR Doc. 2024–10133 Filed 5–8–24; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Request for Information (RFI): Inviting Input Regarding NIDCD's Research Directions in Global Health

AGENCY: National Institutes of Health, HHS.

ACTION: Request for Information.

SUMMARY: The National Institute on Deafness and Other Communication Disorders (NIDCD), National Institutes of Health (NIH) invites input from all interested parties (individuals or groups) on NIDCD's future research directions in Global Health defined for this RFI as international collaboration among researchers in all countries to improve health. NIDCD requests input specifically focused on the NIDCD mission of advancing the science of communication to improve lives.

DATES: Comments will be accepted through July 2, 2024.

ADDRESSES: All responses to this RFI must be submitted electronically via the web-based form at: *https://www.nidcd.nih.gov/nidcd-global-health-rfi-form.* Please include the Notice number in the subject line of your response. Responses to this RFI are voluntary and may be submitted anonymously. You may voluntarily include your name and contact information with your response. If you choose to provide NIH with this information, NIH will not share your name and contact information outside NIH unless required by law.

Other than your name and contact information, please do not include any personally identifiable information or any information that you do not wish to make public. Proprietary, classified, confidential, or sensitive information should not be included in your response. The US Government will use the information submitted in response to this RFI at its discretion. Other than your name and contact information, the Government reserves the right to use any submitted information on public websites, in reports, in summaries of the state of the science, in any possible resultant solicitation(s), grant(s), or cooperative agreement(s), or in the development of future funding opportunities. This RFI is for informational and planning purposes only and is not a solicitation for applications or an obligation on the part of the Government to provide support for any ideas identified in response to it. Please note that the Government will not pay for the preparation of any

information submitted or for use of that information.

FOR FURTHER INFORMATION CONTACT: Specific questions regarding the NIDCD RFI should be directed to: Lana Shekim, Ph.D., Global Health Coordinator National Institute on Deafness and Other Communication Disorders (NIDCD), Phone: 240–723–0306, *NIDCDGlobalHealthRFI@nidcd.nih.gov*.

SUPPLEMENTARY INFORMATION: This notice is in accordance with 42 U.S.C. 285m, of the Public Health Service Act, as amended. The NIDCD's mission is to support research and training on the normal and disordered processes of hearing, balance, taste, smell, voice, speech, and language. Our vision is to advance the science of communication to improve lives. In pursuit of its mission and as outlined in the 2023–2027 Strategic Plan *https://www.nidcd.nih.gov/about/strategic-plans,* NIDCD supports basic, translational, and clinical research on hearing, balance, taste, smell, voice, speech and language. One of the cross-cutting priorities listed in the strategic plan is to participate in international research to improve global health through reducing the burden of hearing loss and communication disorders in the US and around the globe. For more information about current international initiatives related to the NIDCD mission visit *https://www.nidcd.nih.gov/research/global-health*.

International collaboration has a long history at NIDCD in both its intramural laboratories and its support of extramural research, with such research leading to discoveries and advances in knowledge, for example the identification of deafness and stuttering gene variations, and improvements in Brain-Computer Interfaces (BCI) for Communication. A notable example of successful translational research from the hearing program is the development of cochlear implant which resulted from collaboration among multiple scientific disciplines working in the US and collaborating across borders.

NIDCD, like other NIH Institutes, funds highly meritorious research throughout the world, both through direct awards to non-U.S. institutions and indirectly through awards to U.S. institutions. NIDCD is interested in advancing knowledge by strengthening our engagement across the globe in all settings, whether highly resourced or under resourced. By resources, we do not mean just financial resources and include availability of human capital and infrastructure. Reducing the burden of deafness and communication disorders requires a diverse work force that includes physicians, namely otolaryngologists, audiologists, speech-language pathologists, nurses, neuroscientists, psychologists, epidemiologists and many other health and educational professionals. Clinical care may be medical, surgical, pharmacologic or behavioral. Availability of professionals and especially research scientists is uneven within countries and across regions of the world. In the case of communication disorders, knowledge of the language in the area and the culture are essential for effective evaluation and treatment, especially for speech, language and hearing assessment and behavioral intervention.

Recognizing that health is a fundamental human right, so is the right to communicate. NIDCD seeks mutuality of purpose in establishing partnerships across the world to re-imagine a more equitable world.

Information Requested

NIDCD seeks input from a broad array of interested parties, including (but not limited to) people with lived experience or family members, research organizations, academic institutions, multilateral organizations, community organizations, professional societies, businesses, health services organizations, other government agencies and those receiving funding or employed by NIH. NIDCD welcomes thoughts about the appropriateness of the topics below, potential benefits or challenges, suggestions and examples of existing or potential partnerships and any other topic respondents believe is relevant for NIDCD to consider.

Capacity Building: Develop, maintain and renew scientific research capacity of individuals to build future leaders of research in under-resourced and underserved areas in the US and abroad. Addressing current challenges requires a critical mass of capable clinician-scientists and basic scientists that know the language in any given country and understand the cultural and social context.

Strategic partnerships: Build and strengthen strategic partnerships with other NIH Institutes and Centers, other US Government agencies, research funding agencies of other countries, foundations and industry. Doing so would increase strength and sustainability and create synergy for greater public good.

Dissemination and Implementation Research (DIR): Support research and research training in dissemination and implementation research and improve its impact on the health and health care of populations, by fostering rapid integration of research, practice and policy.

WHO Rehabilitation 2030: Advance research on rehabilitation of disorders of voice, speech, language, hearing, balance, taste and smell by promoting transdisciplinary collaboration among researchers funded by NIH Institutes and other US federal agencies working to promote the World Health Organization (WHO) initiative ''Rehabilitation 2030'' *https://www.who.int/initiatives/rehabilitation-2030.*

World Regions: Select regions in the world, continents, or countries, based on opportunities they provide for largest impact, *i.e.,* shared regional language, population size, unique health system, social practice that influences genetic X environmental interaction, availability of research infrastructure or existing partnerships to build on or link to others.

Solutions to Global Workforce Challenges: Work to reduce the brain drain of researchers and health professionals from under resourced areas to highly resourced areas by creating innovative programs that harness the experience and skills of research clinicians across diasporas and engage them in their regions of origin.

We look forward to your input and hope that you will share this RFI opportunity with your colleagues.

Dated: May 3, 2024.

Lisa J. Portnoy,

Acting Executive Officer, National Institute on Deafness and Other Communication Disorders, National Institutes of Health.

[FR Doc. 2024–10096 Filed 5–8–24; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Request for Information on the Development of the Fiscal Years 2026–2030 NIH-Wide Strategic Plan for Sexual & Gender Minority Health Research

AGENCY: National Institutes of Health, HHS.

ACTION: Request for information.

SUMMARY: Through this Request for Information (RFI), the Sexual & Gender Minority Research Office (SGMRO) in the Division of Program Coordination, Planning, and Strategic Initiatives (DPCPSI), Office of the Director (OD), National Institutes of Health (NIH), invites feedback from the scientific research community, clinical practice

communities, patient and family advocates, scientific or professional organizations, federal partners, internal NIH stakeholders, and other interested constituents on the development of the Fiscal Years 2026–2030 NIH-Wide Strategic Plan for Sexual and Gender Minority Health Research. This plan will describe future directions in sexual and gender minority (SGM) health and research to optimize NIH's research investments.

DATES: The SGMRO's RFI is open for public comment for a period of 60 days. Comments must be received on or before 11:59:59 p.m. ET, June 26, 2024, to ensure consideration. After the public comment period has closed, comments received by SGMRO will be considered in a timely manner for the development of the Fiscal Years 2026–2030 NIH-Wide Strategic Plan for SGM Health Research.

How To Submit a Response

All responses should be submitted electronically at the RFI submission website, *https://rfi.grants.nih.gov/?s=660c63fa171bc46e9c038e92,* by 11:59:59 p.m. (ET) on June 26, 2024. You will receive an electronic confirmation acknowledging receipt of your response.

FOR FURTHER INFORMATION CONTACT: Irene Avila, Ph.D., Assistant Director, Sexual & Gender Minority Research Office (SGMRO), *SGMRO@nih.gov*, (301) 594–9701.

SUPPLEMENTARY INFORMATION:

Background: ''Sexual and gender minority'' is an umbrella term that includes, but is not limited to, individuals who identify as lesbian, gay, bisexual, asexual, transgender, Two-Spirit, queer, and/or intersex. Individuals with same-sex or -gender attractions or behaviors and those with variations in sex characteristics are also included. These populations also encompass those who do not self-identify with one of these terms but whose sexual orientation, gender identity or expression, or reproductive development is characterized by non-binary constructs of sexual orientation, gender, and/or sex.

The Sexual and Gender Minority Research Office (SGMRO) at *https://dpcpsi.nih.gov/sgmro* coordinates sexual and gender minority (SGM)–related research and activities by working directly with the National Institutes of Health (NIH) Institutes, Centers, and Offices. The Office was officially established in September 2015 within the NIH Division of Program Coordination, Planning, and Strategic Initiatives in the Office of the Director.

This **Federal Register** notice is in accordance with the 21st Century Cures Act, requiring NIH to regularly update their strategic plans. In 2020, NIH launched its Strategic Plan to Advance Research on the Health and Well-being of Sexual and Gender Minorities, Fiscal Years (FY) 2021–2025 at *https://dpcpsi.nih.gov/sites/default/files/SGMStrategicPlan_2021_2025.pdf.* The current strategic plan is NIH's second strategic plan focused on SGM health research and has provided the NIH with a framework to improve the health of SGM populations through increased research and support of scientists conducting SGM health-related research. In January 2023, SGMRO published a mid-course review at *https://dpcpsi.nih.gov/sites/default/files/2023-09/SGMRO-StrategicPlan-MidCourseReview-Report-5-508.pdf* of the current NIH SGM strategic plan that provided recommendations to support further progress on the goals described therein. To establish NIH priorities in SGM health-related research for the next five years, SGMRO requests input from SGM health, research, and related communities in refining the goals of the FY26–FY30 strategic plan.

Request for Comment on the NIH-Wide SGM Health Research Strategic Plan FY26—FY30: NIH is developing a strategic plan to advance SGM research in FY26–FY30. This RFI invites input from interested parties throughout the scientific research, advocacy, and clinical practice communities, federal partners, those employed by the Department of Health and Human Services (HHS) and NIH or at institutions receiving NIH support as well as the general public, regarding the below topics for the NIH-Wide Strategic Plan for SGM Health Research. This input is a valuable component in developing the SGM health research strategic plan, and the community's time and consideration are appreciated. NIH seeks comments and/or suggestions from all interested parties on the following topics:

- The highest priority needs, and emerging areas of opportunity related to SGM health research at NIH.
- Actions that NIH should prioritize to advance SGM health-related research.
- Partnerships NIH should pursue, both inside and outside of government, to advance SGM health-related research.
- Any other relevant topics that NIH should consider when developing the next NIH-Wide strategic plan for SGM health research.

NIH encourages organizations (*e.g.,* patient advocacy groups, professional organizations) to submit a single response reflective of the views of the organization or membership as a whole. Responses to this RFI are voluntary. Do not include any proprietary, classified, confidential, trade secret, or sensitive information in your response. The responses will be reviewed by NIH staff, and individual feedback will not be provided to any responder. The Government will use the information submitted in response to this RFI at its discretion. The Government reserves the right to use any submitted information on public NIH websites; in reports; in summaries of the state of the science; in any possible resultant solicitation(s), grant(s), or cooperative agreement(s); or in the development of future funding opportunity announcements.

This RFI is for information and planning purposes only and should not be construed as a solicitation for applications or proposals, or as an obligation in any way on the part of the United States Federal Government, NIH, or individual NIH Institutes, Centers, and Offices to provide support for any ideas identified in response to it. The Federal Government will not pay for the preparation of any information submitted or for the Government's use of such information.

No basis for claims against the U.S. Government shall arise as a result of a response to this RFI or from the Government's use of such information. Additionally, the Government cannot guarantee the confidentiality of the information provided.

Dated: May 2, 2024.

Lawrence A. Tabak,

Principal Deputy Director, National Institutes of Health.

[FR Doc. 2024–10134 Filed 5–8–24; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[DOI–2024–0004; FF10T03000 190 FXGO16601025020]

Privacy Act of 1974; System of Records

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Rescindment of system of records notices.

SUMMARY: The Department of the Interior (DOI) is issuing a public notice of its intent to rescind six U.S. Fish and Wildlife Service (FWS) Privacy Act systems of records notices (SORNs), INTERIOR/FWS–5, National Wildlife Refuge Special Use Permits, INTERIOR/FWS–7, Water Development Project

and/or Effluent Discharge Permit Application Review, INTERIOR/FWS–10, National Fish Hatchery Special Use Permits, INTERIOR/FWS–20, Investigative Case File System, INTERIOR/FWS–22, U.S. Deputy Game Warden, and INTERIOR/FWS–30, Marine Mammals Management, Marking, Tagging and Reporting Program. These SORNs have been superseded by a Department-wide or FWS SORN. This rescindment will eliminate unnecessary duplicate notices and promote the overall streamlining and management of DOI Privacy Act systems of records.

DATES: These changes take effect on May 9, 2024.

ADDRESSES: You may send comments identified by docket number [DOI–2024–0004] by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for sending comments.
- *Email: DOI_Privacy@ios.doi.gov.* Include docket number [DOI–2024–0004] in the subject line of the message.
- *U.S. mail or hand-delivery:* Teri Barnett, Departmental Privacy Officer, U.S. Department of the Interior, 1849 C Street NW, Room 7112, Washington, DC 20240.

Instructions: All submissions received must include the agency name and docket number [DOI–2024–0004]. All comments received will be posted without change to *http://www.regulations.gov,* including any personal information provided.

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov.*

You should be aware your entire comment including your personally identifiable information, such as your address, phone number, email address, or any other personal information in your comment, may be made publicly available at any time. While you may request to withhold your personally identifiable information from public review, we cannot guarantee we will be able to do so.

FOR FURTHER INFORMATION CONTACT: Jennifer Schmidt, Associate Privacy Officer, U.S. Fish and Wildlife Service, 5275 Leesburg Pike, MS: IRTM Falls Church, VA 22041–3803, *FWS_Privacy@fws.gov* or (703) 358–2291.

SUPPLEMENTARY INFORMATION: Pursuant to the provisions of the Privacy Act of 1974, as amended, DOI is rescinding the following six FWS SORNs from its system of records inventory. FWS consolidated all permits systems of records under the INTERIOR/FWS–21, Permits System, SORN. FWS also determined during a routine review that the two law enforcement SORNs were superseded by a Department-wide law enforcement SORN, INTERIOR/DOI–10, DOI Law Enforcement Records Management System (LE RMS). Therefore, DOI is rescinding these FWS SORNs to avoid duplication in accordance with the Office of Management and Budget (OMB) Circular A–108, *Federal Agency Responsibilities for Review, Reporting, and Publication under the Privacy Act.*

- INTERIOR/FWS–5, National Wildlife Refuge Special Use Permits. The records in this system were migrated to and are maintained under the consolidated permits system, INTERIOR/FWS–21, Permits System, 89 FR 2230 (January 12, 2024).
- INTERIOR/FWS–7, Water Development Project and/or Effluent Discharge Permit Application Review. The records in this system were migrated to and are maintained under the consolidated permits system, INTERIOR/FWS–21, Permits System, 89 FR 2230 (January 12, 2024).
- INTERIOR/FWS–10, National Fish Hatchery Special Use Permits. The records in this system were migrated to and are maintained under the consolidated permits system, INTERIOR/FWS–21, Permits System, 89 FR 2230 (January 12, 2024).
- INTERIOR/FWS–20, Investigative Case File System. This system supported records of FWS law enforcement activities that are maintained under the Department-wide law enforcement SORN, INTERIOR/DOI–10, DOI Law Enforcement Records Management System (LE RMS), 89 FR 1594 (January 10, 2024).
- INTERIOR/FWS–22, U.S. Deputy Game Warden. This system supported records of FWS law enforcement activities that are maintained under the Department-wide law enforcement SORN, INTERIOR/DOI–10, DOI Law Enforcement Records Management System (LE RMS), 89 FR 1594 (January 10, 2024).
- INTERIOR/FWS–30, Marine Mammals Management, Marking, Tagging and Reporting Program. The records in this system were migrated to and are maintained under the consolidated permits system, INTERIOR/FWS–21, Permits System, 89 FR 2230 (January 12, 2024).

Rescinding these SORNs will have no adverse impacts on individuals as the records previously maintained on FWS permitting activities are covered under the consolidated INTERIOR/FWS–21, Permits System, SORN. FWS law enforcement records are maintained under the published Department-wide law enforcement SORN, INTERIOR/DOI–10, DOI Law Enforcement Records Management System (LE RMS). These rescindments will eliminate unnecessary duplicate notices and promote the overall streamlining and management of DOI Privacy Act systems of records in accordance with the Privacy Act of 1974 and OMB Circular A–108, *Federal Agency Responsibilities for Review, Reporting, and Publication under the Privacy Act.*

SYSTEM NAME AND NUMBER:

1. INTERIOR/FWS–5, National Wildlife Refuge Special Use Permits.
2. INTERIOR/FWS–7, Water Development Project and/or Effluent Discharge Permit Application Review.
3. INTERIOR/FWS–10, National Fish Hatchery Special Use Permits.
4. INTERIOR/FWS–20, Investigative Case File System.
5. INTERIOR/FWS–22, U.S. Deputy Game Warden.
6. INTERIOR/FWS–30, Marine Mammals Management, Marking, Tagging and Reporting Program.

HISTORY:

1. INTERIOR/FWS–5, National Wildlife Refuge Special Use Permits, 64 FR 29055 (May 28, 1999); modification published at 88 FR 16277 (March 16, 2023).
2. INTERIOR/FWS–7, Water Development Project and/or Effluent Discharge Permit Application Review, 46 FR 18367 (March 24, 1981); modification published at 88 FR 16277 (March 16, 2023).
3. INTERIOR/FWS–10, National Fish Hatchery Special Use Permits, 64 FR 29055 (May 28, 1999); modification published at 88 FR 16277 (March 16, 2023).
4. INTERIOR/FWS–20, Investigative Case File System, 64 FR 29055 (May 28, 1999); modification published at 88 FR 16277 (March 16, 2023).
5. INTERIOR/FWS–22, U.S. Deputy Game Warden, 64 FR 29055 (May 28, 1999); modification published at 88 FR 16277 (March 16, 2023).
6. INTERIOR/FWS–30, Marine Mammals Management, Marking, Tagging and Reporting Program, 58 FR 41803 (August 5, 1993); modification published at 88 FR 16277 (March 16, 2023).

Teri Barnett,

Departmental Privacy Officer, U.S. Department of the Interior.

[FR Doc. 2024–10127 Filed 5–8–24; 8:45 am]

BILLING CODE 4333–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

[245A2100DD/AAKC001030/ A0A501010.999900]

HEARTH Act Approval of Nisqually Indian Tribe Residential Leasing Ordinance

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice.

SUMMARY: The Bureau of Indian Affairs (BIA) approved the Nisqually Indian Tribe Residential Leasing Ordinance under the Helping Expedite and Advance Responsible Tribal Homeownership Act of 2012 (HEARTH Act). With this approval, the Tribe is authorized to enter into residential leases without further BIA approval.

DATES: BIA issued the approval on May 2, 2024.

FOR FURTHER INFORMATION CONTACT: Ms. Carla Clark, Bureau of Indian Affairs, Division of Real Estate Services, 1001 Indian School Road NW, Albuquerque, NM 87104, *carla.clark@bia.gov,* (702) 484–3233.

SUPPLEMENTARY INFORMATION:

I. Summary of the HEARTH Act

The HEARTH Act makes a voluntary, alternative land leasing process available to Tribes, by amending the Indian Long-Term Leasing Act of 1955, 25 U.S.C. 415. The HEARTH Act authorizes Tribes to negotiate and enter into business leases of Tribal trust lands with a primary term of 25 years, and up to two renewal terms of 25 years each, without the approval of the Secretary of the Interior (Secretary). The HEARTH Act also authorizes Tribes to enter into leases for residential, recreational, religious or educational purposes for a primary term of up to 75 years without the approval of the Secretary. Participating Tribes develop Tribal Leasing regulations, including an environmental review process, and then must obtain the Secretary's approval of those regulations prior to entering into leases. The HEARTH Act requires the Secretary to approve Tribal regulations if the Tribal regulations are consistent with the Department of the Interior's (Department) leasing regulations at 25 CFR part 162 and provide for an environmental review process that meets requirements set forth in the HEARTH Act. This notice announces that the Secretary, through the Assistant Secretary—Indian Affairs, has approved the Tribal regulations for the Nisqually Indian Tribe.

II. Federal Preemption of State and Local Taxes

The Department's regulations governing the surface leasing of trust and restricted Indian lands specify that, subject to applicable Federal law, permanent improvements on leased land, leasehold or possessory interests, and activities under the lease are not subject to State and local taxation and may be subject to taxation by the Indian Tribe with jurisdiction. *See* 25 CFR162.017. As explained further in the preamble to the final regulations, the Federal government has a strong interest in promoting economic development, self-determination, and Tribal sovereignty. 77 FR 72440, 72447–48 (December 5, 2012). The principles supporting the Federal preemption of State law in the field of Indian leasing and the taxation of lease-related interests and activities applies with equal force to leases entered into under Tribal leasing regulations approved by the Federal government pursuant to the HEARTH Act.

Section 5 of the Indian Reorganization Act, 25 U.S.C. 5108, preempts State and local taxation of permanent improvements on trust land. *Confederated Tribes of the Chehalis Reservation* v. *Thurston County,* 724 F.3d 1153, 1157 (9th Cir. 2013) (citing *Mescalero Apache Tribe* v. *Jones,* 411 U.S. 145 (1973)). Similarly, 25 U.S.C. 5108 preempts State taxation of rent payments by a lessee for leased trust lands, because ''tax on the payment of rent is indistinguishable from an impermissible tax on the land.'' *See Seminole Tribe of Florida* v. *Stranburg,* 799 F.3d 1324, 1331, n.8 (11th Cir. 2015). In addition, as explained in the preamble to the revised leasing regulations at 25 CFR part 162, Federal courts have applied a balancing test to determine whether State and local taxation of non-Indians on the reservation is preempted. *White Mountain Apache Tribe* v. *Bracker,* 448 U.S. 136, 143 (1980). The *Bracker* balancing test, which is conducted against a backdrop of ''traditional notions of Indian self- government,'' requires a particularized examination of the relevant State, Federal, and Tribal interests. We hereby adopt the *Bracker* analysis from the preamble to the surface leasing regulations, 77 FR at 72447–48, as supplemented by the analysis below.

The strong Federal and Tribal interests against State and local taxation of improvements, leaseholds, and activities on land leased under the Department's leasing regulations apply equally to improvements, leaseholds, and activities on land leased pursuant to Tribal leasing regulations approved under the HEARTH Act. Congress's overarching intent was to ''allow Tribes to exercise greater control over their own land, support self-determination, and eliminate bureaucratic delays that stand in the way of homeownership and economic development in Tribal communities.'' 158 Cong. Rec. H. 2682 (May 15, 2012). The HEARTH Act was intended to afford Tribes ''flexibility to adapt lease terms to suit [their] business and cultural needs'' and to ''enable [Tribes] to approve leases quickly and efficiently.'' H. Rep. 112–427 at 6 (2012).

Assessment of State and local taxes would obstruct these express Federal policies supporting Tribal economic development and self-determination, and also threaten substantial Tribal interests in effective Tribal government, economic self-sufficiency, and territorial autonomy. *See Michigan* v. *Bay Mills Indian Community,* 572 U.S. 782, 810 (2014) (Sotomayor, J., concurring) (determining that ''[a] key goal of the Federal Government is to render Tribes more self-sufficient, and better positioned to fund their own sovereign functions, rather than relying on Federal funding''). The additional costs of State and local taxation have a chilling effect on potential lessees, as well as on a Tribe that, as a result, might refrain from exercising its own sovereign right to impose a Tribal tax to support its infrastructure needs. *See id.* at 810–11 (finding that State and local taxes greatly discourage Tribes from raising tax revenue from the same sources because the imposition of double taxation would impede Tribal economic growth).

Similar to BIA's surface leasing regulations, Tribal regulations under the HEARTH Act pervasively cover all aspects of leasing. *See* 25 U.S.C. 415(h)(3)(B)(i) (requiring Tribal regulations be consistent with BIA surface leasing regulations). Furthermore, the Federal government remains involved in the Tribal land leasing process by approving the Tribal leasing regulations in the first instance and providing technical assistance, upon request by a Tribe, for the development of an environmental review process. The Secretary also retains authority to take any necessary actions to remedy violations of a lease or of the Tribal regulations, including terminating the lease or rescinding approval of the Tribal regulations and reassuming lease approval responsibilities. Moreover, the Secretary continues to review, approve, and monitor individual Indian land leases

and other types of leases not covered under the Tribal regulations according to the 25 CFR part 162.

Accordingly, the Federal and Tribal interests weigh heavily in favor of preemption of State and local taxes on lease-related activities and interests, regardless of whether the lease is governed by Tribal leasing regulations or 25 CFR part 162. Improvements, activities, and leasehold or possessory interests may be subject to taxation by the Nisqually Indian Tribe.

Bryan Newland,

Assistant Secretary—Indian Affairs.

[FR Doc. 2024–10072 Filed 5–8–24; 8:45 am]

BILLING CODE 4337–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

[245A2100DD/AAKC001030/A0A501010.999900]

HEARTH Act Approval of Confederated Tribes of the Warm Springs Reservation of Oregon Amended Business Leasing Ordinance

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice.

SUMMARY: The Bureau of Indian Affairs (BIA) approved the Confederated Tribes of the Warm Springs Reservation of Oregon Amended Business Leasing Ordinance under the Helping Expedite and Advance Responsible Tribal Homeownership Act of 2012 (HEARTH Act). With this approval, the Tribe is authorized to enter into business, wind and solar, and wind energy evaluation leases without further BIA approval.

DATES: BIA issued the approval on May 2, 2024.

FOR FURTHER INFORMATION CONTACT: Ms. Carla Clark, Bureau of Indian Affairs, Division of Real Estate Services, 1001 Indian School Road NW, Albuquerque, NM 87104, *carla.clark@bia.gov,* (702) 484–3233.

SUPPLEMENTARY INFORMATION:

I. Summary of the HEARTH Act

The HEARTH Act makes a voluntary, alternative land leasing process available to Tribes, by amending the Indian Long-Term Leasing Act of 1955, 25 U.S.C. 415. The HEARTH Act authorizes Tribes to negotiate and enter into business leases of Tribal trust lands with a primary term of 25 years, and up to two renewal terms of 25 years each, without the approval of the Secretary of the Interior (Secretary). The HEARTH Act also authorizes Tribes to enter into leases for residential, recreational, religious or educational purposes for a primary term of up to 75 years without the approval of the Secretary. Participating Tribes develop Tribal Leasing regulations, including an environmental review process, and then must obtain the Secretary's approval of those regulations prior to entering into leases. The HEARTH Act requires the Secretary to approve Tribal regulations if the Tribal regulations are consistent with the Department of the Interior's (Department) leasing regulations at 25 CFR part 162 and provide for an environmental review process that meets requirements set forth in the HEARTH Act. This notice announces that the Secretary, through the Assistant Secretary—Indian Affairs, has approved the Tribal regulations for the Confederated Tribes of the Warm Springs Reservation of Oregon.

II. Federal Preemption of State and Local Taxes

The Department's regulations governing the surface leasing of trust and restricted Indian lands specify that, subject to applicable Federal law, permanent improvements on leased land, leasehold or possessory interests, and activities under the lease are not subject to State and local taxation and may be subject to taxation by the Indian Tribe with jurisdiction. *See* 25 CFR 162.017. As explained further in the preamble to the final regulations, the Federal government has a strong interest in promoting economic development, self-determination, and Tribal sovereignty. 77 FR 72440, 72447–48 (December 5, 2012). The principles supporting the Federal preemption of State law in the field of Indian leasing and the taxation of lease-related interests and activities applies with equal force to leases entered into under Tribal leasing regulations approved by the Federal government pursuant to the HEARTH Act.

Section 5 of the Indian Reorganization Act (IRA), 25 U.S.C. 5108, preempts State and local taxation of permanent improvements on trust land. *Confederated Tribes of the Chehalis Reservation* v. *Thurston County,* 724 F.3d 1153, 1157 (9th Cir. 2013) (citing *Mescalero Apache Tribe* v. *Jones,* 411 U.S. 145 (1973)). Similarly, 25 U.S.C 5108 preempts State taxation of rent payments by a lessee for leased trust lands, because ''tax on the payment of rent is indistinguishable from an impermissible tax on the land.'' *See Seminole Tribe of Florida* v. *Stranburg,* 799 F.3d 1324, 1331, n.8 (11th Cir. 2015). In addition, as explained in the preamble to the revised leasing regulations at 25 CFR part 162, Federal courts have applied a balancing test to determine whether State and local taxation of non-Indians on the reservation is preempted. *White Mountain Apache Tribe* v. *Bracker,* 448 U.S. 136, 143 (1980). The *Bracker* balancing test, which is conducted against a backdrop of ''traditional notions of Indian self-government,'' requires a particularized examination of the relevant State, Federal, and Tribal interests. We hereby adopt the *Bracker* analysis from the preamble to the surface leasing regulations, 77 FR at 72447–48, as supplemented by the analysis below.

The strong Federal and Tribal interests against State and local taxation of improvements, leaseholds, and activities on land leased under the Department's leasing regulations apply equally to improvements, leaseholds, and activities on land leased pursuant to Tribal leasing regulations approved under the HEARTH Act. Congress's overarching intent was to ''allow Tribes to exercise greater control over their own land, support self-determination, and eliminate bureaucratic delays that stand in the way of homeownership and economic development in Tribal communities.'' 158 Cong. Rec. H. 2682 (May 15, 2012). The HEARTH Act was intended to afford Tribes ''flexibility to adapt lease terms to suit [their] business and cultural needs'' and to ''enable [Tribes] to approve leases quickly and efficiently.'' H. Rep. 112–427 at 6 (2012).

Assessment of State and local taxes would obstruct these express Federal policies supporting Tribal economic development and self-determination, and also threaten substantial Tribal interests in effective Tribal government, economic self-sufficiency, and territorial autonomy. *See Michigan* v. *Bay Mills Indian Community,* 572 U.S. 782, 810 (2014) (Sotomayor, J., concurring) (determining that ''[a] key goal of the Federal Government is to render Tribes more self-sufficient, and better positioned to fund their own sovereign functions, rather than relying on Federal funding''). The additional costs of State and local taxation have a chilling effect on potential lessees, as well as on a Tribe that, as a result, might refrain from exercising its own sovereign right to impose a Tribal tax to support its infrastructure needs. *See id.* at 810–11 (finding that State and local taxes greatly discourage Tribes from raising tax revenue from the same sources because the imposition of double taxation would impede Tribal economic growth).

Similar to BIA's surface leasing regulations, Tribal regulations under the HEARTH Act pervasively cover all aspects of leasing. *See* 25 U.S.C. 415(h)(3)(B)(i) (requiring Tribal regulations be consistent with BIA surface leasing regulations). Furthermore, the Federal government remains involved in the Tribal land leasing process by approving the Tribal leasing regulations in the first instance and providing technical assistance, upon request by a Tribe, for the development of an environmental review process. The Secretary also retains authority to take any necessary actions to remedy violations of a lease or of the Tribal regulations, including terminating the lease or rescinding approval of the Tribal regulations and reassuming lease approval responsibilities. Moreover, the Secretary continues to review, approve, and monitor individual Indian land leases and other types of leases not covered under the Tribal regulations according to 25 CFR part 162.

Accordingly, the Federal and Tribal interests weigh heavily in favor of preemption of State and local taxes on lease-related activities and interests, regardless of whether the lease is governed by Tribal leasing regulations or 25 CFR part 162. Improvements, activities, and leasehold or possessory interests may be subject to taxation by the Confederated Tribes of the Warm Springs Reservation of Oregon.

Bryan Newland,

Assistant Secretary—Indian Affairs.

[FR Doc. 2024–10073 Filed 5–8–24; 8:45 am]

BILLING CODE 4337–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[BLM_CA_FRN_MO4500174427]

Notice of New Recreation Fees on Public Lands in Humboldt, Trinity, and Shasta Counties, CA

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of new recreation fees.

SUMMARY: Pursuant to the Federal Lands Recreation Enhancement Act, the Northern California District Office of the Bureau of Land Management (BLM) is providing notice that the Arcata Field Office, King Range National Conservation Area (NCA) is implementing a new Individual Special Recreation Permit (ISRP) fee for overnight use in the King Range Wilderness, and the Redding Field Office is implementing a new fee for overnight camping at Steiner Flat Campground and Ohl Olsen Campground.

DATES: The new fees at the King Range NCA and Ohl Olsen Campground will take effect November 12, 2024, and the new fees at the Steiner Flat campground will take effect when the upgrades listed in this notice are complete or November 12, 2024, whichever is later.

ADDRESSES: Please send comments to the BLM Northern California District Office, 6640 Lockheed Dr. Redding, California 96002, or by email at *BLM_CA_Web_RE@blm.gov.*

FOR FURTHER INFORMATION CONTACT: Public Affairs Officer Joseph J. Fontana, telephone: 530–260–0189; email: *jfontana@blm.gov.* Individuals in the United States who are deaf, deafblind, hard of hearing, or have a speech disability may dial 711 (TTY, TDD, or TeleBraille) to access telecommunications relay services. Individuals outside the United States should use the relay services offered within their country to make international calls to contact Mr. Fontana in the United States.

SUPPLEMENTARY INFORMATION: Fees help ensure that those who recreate on public lands make a greater, but reasonable, contribution toward protecting and enhancing those opportunities than those who do not utilize recreation opportunities. Information about the use of the fee revenues will be posted at one or more kiosks within the fee areas annually.

King Range NCA

The BLM will implement a fee of $12 per person per overnight trip (maximum stay per trip is 14 days) in the King Range Wilderness. There will be no fee for children 16 and under and no fee for day use.

The King Range NCA encompasses 68,000 acres of public lands along 35 miles of coastline, draws people from all over the world to visit the ''Lost Coast'' of California, and offers one of the only coastal backpacking opportunities in the contiguous United States. Providing safety and trip planning support for visitors is important due to the unique safety issues associated with a coastal wilderness environment, including the influence of tides, waves, and storms.

The King Range NCA is managed as a ''Special Area'' and is a component of the BLM's National Landscape Conservation System. Special Areas are defined as areas officially designated by statute, Presidential decree, or Secretarial order and include components of the National Wilderness Preservation System. The 2005 King Range NCA Resource Management Plan directed the BLM to establish visitor carrying capacities, a permit system, and a fee schedule for overnight backcountry use. Since 2017, overnight visitation in the King Range Wilderness has been managed with a free ISRP issued through *www.recreation.gov.*

In accordance with the BLM recreation fee program policy, the King Range NCA developed a business plan in 2023 to establish future management goals and priorities to determine how the BLM intends to use fees to improve and maintain visitor services. As discussed in the business plan, the ISRP fee for overnight visitation in the King Range Wilderness is consistent with other established fee sites for similar areas. The BLM has notified and involved the public throughout this process and released the draft business plan for a public comment period from April 21 to May 22, 2023. The BLM presented the proposed project and the results of the public comment period to the Northern California Resource Advisory Council (RAC) on October 26, 2023. The RAC supported the fees as provided in the business plan.

Redding Field Office

The BLM will implement a new $15 fee for overnight camping at Steiner Flat Campground, located near Douglas City, California, along the Trinity River. The campground will be upgraded to include the following amenities: toilets, trash service, increased park ranger and law enforcement presence, and campsites with campfire rings, tables, bear-proof food storage boxes, and tent pads. The upgraded amenities will help reduce environmental impacts and improve the experience for those using the site. Fees will begin when all the amenities are available in the campground or 6 months after this notice is published, whichever is later.

Ohl Olsen Campground is a group-use campground near Shasta Lake City, California, in the Chappie-Shasta Off-Highway-Vehicle Area. The BLM will implement a new fee of $60 per night for the lower site (maximum of 30 people) and $80 per night for the upper site (maximum of 50 people).

In accordance with the BLM recreation fee program policy, the Redding Field Office finalized a business plan in 2023 to establish future management goals and priorities for the recreation fee program. As discussed in the business plan, the overnight camping fees for Steiner Flat Campground and Ohl Olsen Campground are consistent with other established fee sites for similar areas

and services. The BLM has notified and involved the public throughout this process and released the draft business plan for a public comment period from October 4 to November 2, 2021. The BLM presented the proposed project and the results of the public comment period to the Northern California RAC on October 26, 2023. The RAC supported the fees as provided in the business plan.

(Authority: 16 U.S.C. 6803(b).)

Elizabeth Meyer-Shields,

Deputy State Director, Natural Resources.

[FR Doc. 2024–10163 Filed 5–8–24; 8:45 am]

BILLING CODE 4331–15–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[DOI–2023–0025; LLHQ500000, L18500000.YC0000, LIITADC10000, 245]

Privacy Act of 1974; System of Records

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of a modified system of records.

SUMMARY: Pursuant to the provisions of the Privacy Act of 1974, as amended, the Department of the Interior (DOI) is issuing a public notice of its intent to modify the Bureau of Land Management (BLM) Privacy Act system of records, INTERIOR/BLM–16, Timber Sale Information System (TSIS). DOI is publishing this revised system of records notice (SORN) to change the system name to INTERIOR/BLM–16, Forest Resources Information System (FRIS), to provide organizational clarification related to the overall management of the forest resources program and to update all sections of the notice in accordance with the Office of Management and Budget (OMB) policy. This modified system will be included in DOI's inventory of record systems.

DATES: This modified system will be effective upon publication. New or modified routine uses will be effective June 10, 2024. Submit comments on or before June 10, 2024.

ADDRESSES: You may send comments identified by docket number [DOI–2023–0025] by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for sending comments.
- *Email: DOI_Privacy@ios.doi.gov.* Include docket number [DOI–2023–0025] in the subject line of the message.
- *U.S. mail or hand-delivery:* Teri Barnett, Departmental Privacy Officer, U.S. Department of the Interior, 1849 C Street NW, Room 7112, Washington, DC 20240.

Instructions: All submissions received must include the agency name and docket number [DOI–2023–0025]. All comments received will be posted without change to *http://www.regulations.gov,* including any personal information provided.

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Ashanti Murphy-Jones, Acting Associate Privacy Officer, Bureau of Land Management, 1849 C Street NW, Room No. 5644, Washington, DC 20240, *blm_wo_privacy@blm.gov* or (202) 365–1429.

SUPPLEMENTARY INFORMATION:

I. Background

BLM maintains the INTERIOR/BLM–16, Timber Sale Information System (TSIS), system of records to support the management and tracking of forest resources, including timber sale, accounting, management, and activity tracking; stewardship contract management and activity; and special consolidated reporting. Each of these modules provide direct support to the BLM mission goals related to managing the use of forest and woodland products in the Public Domain (PD) and in the Oregon and California Grant Lands (O&C).

DOI is publishing this revised notice to change the system name from INTERIOR/BLM–16, Timber Sale Information System (TSIS), to INTERIOR/BLM–16, Forest Resources Information System (FRIS), to provide organizational clarification for the overall forest resources program. DOI is also adding a new purpose section to describe the primary purpose of FRIS; updating the system location to reflect a move to a DOI data center and the cloud environment; updating the system manager section, authorities for maintenance of the system, and the records source categories section to provide additional clarification on individual sources of information; updating the policies and practices for retention of records section to clarify the records retention schedule; updating safeguards to protect records; and providing an updated description on the retrieval of records. DOI is further expanding the categories of individuals to provide clarification on the individuals covered by the system and the categories of records to reflect additional types of records that are maintained in the system; and updating the records access, contesting record, and notification procedures to provide guidance on how individuals may submit requests under the Privacy Act. This notice also reorganizes the sections and updates section titles in accordance with OMB Circular A–108, *Federal Agency Responsibilities for Review, Reporting, and Publication under the Privacy Act.*

The existing routine uses are being updated from a numeric to alphabetic list and are being modified to provide clarity and transparency and reflect updates consistent with standard DOI routine uses. Additionally, DOI is proposing new routine uses to facilitate sharing of information with agencies and organizations to promote the integrity of the records in the system or carry out a statutory responsibility of the DOI or Federal government.

Routine use A was slightly modified to further clarify disclosures to the Department of Justice (DOJ) or other Federal agencies, when necessary, in relation to litigation or judicial hearings. Routine use B was modified to clarify disclosures to a congressional office to respond to or resolve an individual's request made to that office. Routine use H was slightly modified to include sharing of information with territorial government agencies in response to court orders or for discovery purposes related to litigation. Routine use I was modified to include grantees and shared service providers to facilitate sharing of information when authorized and necessary to perform services on DOI's behalf. Modified routine use J allows DOI and BLM to share information with appropriate Federal agencies or entities when reasonably necessary to respond to a breach of PII and to prevent, minimize, or remedy the risk of harm to individuals or the Federal government in accordance with OMB Memorandum M–17–12, *Preparing for and Responding to a Breach of Personally Identifiable Information.* Routine use N was modified to clarify sharing with the news media and the public where there is a legitimate public interest or in support of a legitimate law enforcement or public safety function.

Proposed routine use C facilitates sharing of information with the Executive Office of the President to resolve issues concerning individuals' records. BLM is removing the former routine use 13 for disclosure to consumer reporting agencies and has included that notice at the end of this section.

Pursuant to the Privacy Act, 5 U.S.C. 552a(b)(12), DOI may disclose

information from this system to consumer reporting agencies as defined in the Fair Credit Reporting Act (15 U.S.C. 1681a(f)) or the Federal Claims Collection Act of 1966 (31 U.S.C. 3701(a)(3)) to aid in the collection of outstanding debts owed to the Federal Government.

II. Privacy Act

The Privacy Act of 1974, as amended, embodies fair information practice principles in a statutory framework governing how Federal agencies collect, maintain, use, and disseminate individuals' records. The Privacy Act applies to records about individuals that are maintained in a ''system of records.'' A ''system of records'' is a group of any records under the control of an agency from which information is retrieved by the name of an individual or by some identifying number, symbol, or other identifying information assigned to the individual. The Privacy Act defines an individual as a United States citizen or lawful permanent resident. Individuals may request access to their own records that are maintained in a system of records in the possession or under the control of DOI by complying with DOI Privacy Act regulations at 43 CFR part 2, subpart K, and following the procedures outlined in the Records Access, Contesting Record, and Notification Procedures sections of this notice.

The Privacy Act requires each agency to publish in the **Federal Register** a description denoting the existence and character of each system of records that the agency maintains, and the routine uses of each system. The INTERIOR/BLM–16, Forest Resources Information System (FRIS), SORN is published in its entirety below. In accordance with 5 U.S.C. 552a(r), DOI has provided a report of this system of records to the OMB and to Congress.

III. Public Participation

You should be aware your entire comment including your personally identifiable information, such as your address, phone number, email address, or any other personal information in your comment, may be made publicly available at any time. While you may request to withhold your personally identifiable information from public review, we cannot guarantee we will be able to do so.

SYSTEM NAME AND NUMBER:

INTERIOR/BLM–16, Forest Resources Information System (FRIS).

SECURITY CLASSIFICATION:

Unclassified.

SYSTEM LOCATION:

Records are maintained at National Operations Center, Bureau of Land Management, U.S. Department of the Interior, 6th Avenue & Kipling Boulevard, Denver Federal Center, Building 50, Denver, Colorado 80225. Records may also be located in a cloud location managed by the DOI.

SYSTEM MANAGER(S):

Deputy State Director, Division of Resources, Lands, and Minerals (OR930), Oregon State Office, Bureau of Land Management, U.S. Department of the Interior, P.O. Box 2965, Portland, OR 97208.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

Exportation of unprocessed timber from Federal lands, 16 U.S.C. 617; Mineral Materials Act of 1947, 30 U.S.C. 601; Oregon and California Revested Lands Sustained Yield Management Act of 1937, 43 U.S.C. 2601; Healthy Forests Restoration Act of 2003, Public Law 108–148; Agricultural Act of 2014, Public Law 113–79.

PURPOSE(S) OF THE SYSTEM:

The primary purpose of FRIS is to track and record BLM's Forest management lifecycle activity. FRIS provides users with a suite of computational tools and procedures for managing activities associated with the management of forest resources. FRIS provides the tools for managing BLM timber sale contracts; special forest product permits, stewardship contracting process, non-contracted forest depletions, forest treatment spatial extents, pre/post contract forest inventory, timber volumes and appraisals, protest appeals, forest trespass activity, and reports.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

The categories of the individuals covered in the system include members of the public entering a forestry products contract with BLM or individual appellants associated with a forestry management decision. These include timber purchasers/contractors (*i.e.,* individual, partnership, corporate); contact person(s) for timber purchaser/contractor; permittees (*i.e.,* individual or contractor) of special forest products; and appellant (*i.e.,* individual or organization) of forestry management decision.

This system contains records concerning corporations and other business entities, which are not subject to the Privacy Act. However, records pertaining to individuals acting on behalf of corporations and other business entities may reflect personal information that may be maintained in this system of records.

CATEGORIES OF RECORDS IN THE SYSTEM:

The system contains records related to the management of forest resources. The records contain BLM timber sale contracts, special forest product permits, stewardship contracting process, non-contracted forest depletions, forest treatment spatial extents, pre/post contract forest inventory, timber volumes and appraisals, protest, appeals, forest trespass activity, and reports.

These records for purchaser contracts include business name, address, and designated representatives, timber quantity, contract price, BLM assigned contract number, and information on debts owed to BLM because of defective payments. These documents also contain the BLM contractor officer's name and title.

For permits issued to the public, the information may include individuals name, citizenship, personal email address, mailing/home address, personal phone numbers, driver's license, vehicle information, license plate information, and description of the material purchased.

RECORD SOURCE CATEGORIES:

The sources of information in the system include purchasers, purchasers' contracts, and holders of forest product permits, which can be collected on the FRIS public facing website, in person at a BLM facility, or from an authorized BLM Contracting Officer.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND PURPOSES OF SUCH USES:

In addition to those disclosures generally permitted under 5 U.S.C. 552a(b) of the Privacy Act, all or a portion of the records or information contained in this system may be disclosed outside DOI as a routine use pursuant to 5 U.S.C. 552a(b)(3) as follows:

A. To the Department of Justice (DOJ), including Offices of the U.S. Attorneys, or other Federal agency conducting litigation or in proceedings before any court, adjudicative, or administrative body when it is relevant or necessary to the litigation and one of the following is a party to the litigation or has an interest in such litigation:

(1) DOI or any component of DOI;

(2) Any other Federal agency appearing before the Office of Hearings and Appeals;

(3) Any DOI employee or former employee acting in his or her official capacity;

(4) Any DOI employee or former employee acting in his or her individual capacity if DOI or DOJ has agreed to represent that employee or pay for private representation of the employee; or

(5) The U.S. Government or any agency thereof, when DOJ determines that DOI is likely to be affected by the proceeding.

B. To a congressional office when requesting information on behalf of, and at the request of, the individual who is the subject of the record.

C. To the Executive Office of the President in response to an inquiry from that office made at the request of the subject of a record or a third party on that person's behalf, or for a purpose compatible with the reason for which the records are collected or maintained.

D. To any criminal, civil, or regulatory law enforcement authority (whether Federal, State, territorial, local, or Tribal or foreign) when a record, either alone or in conjunction with other information, indicates a violation or potential violation of law—criminal, civil, or regulatory in nature, and the disclosure is compatible with the purpose for which the records were compiled.

E. To an official of another Federal agency to provide information needed in the performance of official duties related to reconciling or reconstructing data files or to enable that agency to respond to an inquiry by the individual to whom the record pertains.

F. To Federal, State, territorial, local, Tribal, or foreign agencies that have requested information relevant or necessary to the hiring, firing, or retention of an employee or contractor, or the issuance of a security clearance, license, contract, grant or other benefit, when the disclosure is compatible with the purpose for which the records were compiled.

G. To representatives of the National Archives and Records Administration to conduct records management inspections under the authority of 44 U.S.C. 2904 and 2906.

H. To State, territorial, and local governments and Tribal organizations or their representatives to provide information needed in response to court order and/or discovery purposes related to litigation, when the disclosure is compatible with the purpose for which the records were compiled.

I. To an expert, consultant, grantee, shared service provider, or contractor (including employees of the contractor) of DOI that performs services requiring access to these records on DOI's behalf to carry out the purposes of the system.

J. To appropriate agencies, entities, and persons when:

(1) DOI suspects or has confirmed that there has been a breach of the system of records;

(2) DOI has determined that as a result of the suspected or confirmed breach, there is a risk of harm to individuals, DOI (including its information systems, programs, and operations), the Federal government, or national security; and

(3) the disclosure made to such agencies, entities, and persons is reasonably necessary to assist in connection with DOI's efforts to respond to the suspected or confirmed breach or to prevent, minimize, or remedy such harm.

K. To another Federal agency or Federal entity, when DOI determines that information from this system of records is reasonably necessary to assist the recipient agency or entity in:

(1) responding to a suspected or confirmed breach; or

(2) preventing, minimizing, or remedying the risk of harm to individuals, the recipient agency or entity (including its information systems, programs, and operations), the Federal Government, or national security, resulting from a suspected or confirmed breach.

L. To the Office of Management and Budget (OMB) during the coordination and clearance process in connection with legislative affairs as mandated by OMB Circular A–19.

M. To the Department of the Treasury to recover debts owed to the United States.

N. To the news media and the public, with the approval of the Public Affairs Officer in consultation with counsel and the Senior Agency Official for Privacy, where there exists a legitimate public interest in the disclosure of the information, except to the extent it is determined that release of the specific information in the context of a particular case would constitute an unwarranted invasion of personal privacy.

POLICIES AND PRACTICES FOR STORAGE OF RECORDS:

Paper records are contained in file folders stored within locked file cabinets. Electronic records are stored on disk, system hard drive, tape, or other appropriate media.

POLICIES AND PRACTICES FOR RETRIEVAL OF RECORDS:

Records may be retrieved by permit or contract number, name, purchaser or permittee name, address, email, and phone number.

POLICIES AND PRACTICES FOR RETENTION AND DISPOSAL OF RECORDS:

Records in this system are retained in accordance with NARA procedures and Department Records Schedule (DRS)/General Records Schedule (GRS)/BLM Records Retention Catalog, under 4/6g(1), Forest Resource Information System. This schedule has been approved by NARA under Job Number N1–049–09–3, 1a. The records disposition is permanent. A copy of the master file is transferred to NARA along with the technical documentation in accordance with 36 CFR 1235.44–50. Thereafter, a copy transfers every 5 years along with the current technical documentation.

ADMINISTRATIVE, TECHNICAL, AND PHYSICAL SAFEGUARDS:

The records contained in this system are safeguarded in accordance with 43 CFR 2.226 and other applicable security and privacy rules and policies. During normal hours of operation, paper records are maintained in secure cabinets and/or in secure file rooms under the control of authorized personnel.

Computerized records systems follow the National Institute of Standards and Technology privacy and security standards as developed to comply with the Privacy Act of 1974, as amended, 5 U.S.C. 552a; Paperwork Reduction Act of 1995, 44 U.S.C. 3501 *et seq.;* Federal Information Security Modernization Act of 2014, 44 U.S.C. 3551 *et seq.;* and the Federal Information Processing Standards 199: Standards for Security Categorization of Federal Information and Information Systems. Security controls include user identification, passwords, multi-factor authentication, database permissions, firewalls, audit logs, and network system security monitoring, and software controls.

Access to records in the system is limited to authorized personnel who have a need to access the records in the performance of their official duties, and each user's access is restricted to only the functions and data necessary to perform that person's job responsibilities. System administrators and authorized users are trained and required to follow established internal security protocols and must complete all security, privacy, and records management training and sign the DOI Rules of Behavior. A Privacy Impact Assessment was completed for the associated information systems to ensure that Privacy Act requirements are met, and appropriate privacy controls were implemented to safeguard the personally identifiable information contained in the systems.

RECORD ACCESS PROCEDURES:

An individual requesting access to their records should send a written inquiry to the applicable System Manager identified above. DOI forms and instructions for submitting a Privacy Act request may be obtained from the DOI Privacy Act Requests website at *https://www.doi.gov/privacy/privacy-act-requests.* The request must include a general description of the records sought and the requester's full name, current address, and sufficient identifying information such as date of birth or other information required for verification of the requester's identity. The request must be signed and dated and be either notarized or submitted under penalty of perjury in accordance with 28 U.S.C. 1746. Requests submitted by mail must be clearly marked ''PRIVACY ACT REQUEST FOR ACCESS'' on both the envelope and letter. A request for access must meet the requirements of 43 CFR 2.238.

CONTESTING RECORD PROCEDURES:

An individual requesting amendment of their records should send a written request to the applicable System Manager as identified above. DOI instructions for submitting a request for amendment of records are available on the DOI Privacy Act Requests website at *https://www.doi.gov/privacy/privacy-act-requests.* The request must clearly identify the records for which amendment is being sought, the reasons for requesting the amendment, and the proposed amendment to the record. The request must include the requester's full name, current address, and sufficient identifying information such as date of birth or other information required for verification of the requester's identity. The request must be signed and dated and be either notarized or submitted under penalty of perjury in accordance with 28 U.S.C. 1746. Requests submitted by mail must be clearly marked ''PRIVACY ACT REQUEST FOR AMENDMENT'' on both the envelope and letter. A request for amendment must meet the requirements of 43 CFR 2.246.

NOTIFICATION PROCEDURES:

An individual requesting notification of the existence of records about them should send a written inquiry to the applicable System Manager as identified above. DOI instructions for submitting a request for notification are available on the DOI Privacy Act Requests website at *https://www.doi.gov/privacy/privacy-act-requests.* The request must include a general description of the records and the requester's full name, current address, and sufficient identifying information such as date of birth or other information required for verification of the requester's identity. The request must be signed and dated and be either notarized or submitted under penalty of perjury in accordance with 28 U.S.C. 1746. Requests submitted by mail must be clearly marked ''PRIVACY ACT INQUIRY'' on both the envelope and letter. A request for notification must meet the requirements of 43 CFR 2.235.

EXEMPTIONS PROMULGATED FOR THE SYSTEM:

None.

HISTORY:

75 FR 3919 (January 25, 2010), modification published at 86 FR 50156 (September 7, 2021).

Teri Barnett,

Departmental Privacy Officer, U.S. Department of the Interior.

[FR Doc. 2024–10144 Filed 5–8–24; 8:45 am]

BILLING CODE 4130–84–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0037882; PPWOCRADN0–PCU00RP14.R50000]

Notice of Intended Repatriation: California State University, Sacramento, Sacramento, CA

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the California State University, Sacramento intends to repatriate certain cultural items that meet the definition of sacred objects or objects of cultural patrimony and that have a cultural affiliation with the Indian Tribes or Native Hawaiian organizations in this notice.

DATES: Repatriation of the cultural items in this notice may occur on or after June 10, 2024.

ADDRESSES: Dr. Mark Wheeler, Senior Advisor to President Luke Wood, California State University, Sacramento, 6000 J Street Sacramento, CA 95819, telephone (916) 460–0490, email *mark.wheeler@csus.edu.*

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the California State University, Sacramento, and additional information on the determinations in this notice, including the results of consultation, can be found in the summary or related records. The National Park Service is not responsible for the determinations in this notice.

Abstract of Information Available

A total of 311 cultural items have been requested for repatriation.

In 1964–71, Stephen Humphreys, a student at Sacramento State College, conducted extensive surveys and excavations in the region between Oroville and Paradise in Butte County, California. Humphries surfaced collected from CA–BUT–60 (Vine Rockshelter), BUT–61 (Bow Shaft Rockshelter), BUT–303 (Gold Flat #1), and BUT–304 (Gold Flat #2). The 15 objects of cultural patrimony from BUT–60 are flaked stone tools and a steatite vessel. The three sacred objects are perishable botanical remains. The 69 objects of cultural patrimony from CA–BUT–61 are flaked and modified stone objects; the 53 sacred objects are pigment, worked wood and bone objects, glass and shell beads, crystals, and animal remains. The 171 objects of cultural patrimony from BUT–303/304 are modified stone, ground stone, flaked stone, unmodified stone, and animal remains. An unknown number of objects may be missing from the collection, and California State University, Sacramento continues to look for them.

Determinations

The California State University, Sacramento has determined that:

- The 56 sacred objects described in this notice are specific ceremonial objects needed by a traditional Native American religious leader for present-day adherents to practice traditional Native American religion, according to the Native American traditional knowledge of a lineal descendant, Indian Tribe, or Native Hawaiian organization.
- The 255 objects of cultural patrimony described in this notice have ongoing historical, traditional, or cultural importance central to the Native American group, including any constituent sub-group (such as a band, clan, lineage, ceremonial society, or other subdivision), according to the Native American traditional knowledge of an Indian Tribe or Native Hawaiian organization.
- There is a reasonable connection between the cultural items described in this notice and the Mechoopda Indian Tribe of Chico Rancheria, California.

Requests for Repatriation

Additional, written requests for repatriation of the cultural items in this

notice must be sent to the authorized representative identified in this notice under **ADDRESSES**. Requests for repatriation may be submitted by any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the cultural items in this notice to a requestor may occur on or after June 10, 2024. If competing requests for repatriation are received, the California State University, Sacramento must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the cultural items are considered a single request and not competing requests. The California State University, Sacramento is responsible for sending a copy of this notice to the Indian Tribes and Native Hawaiian organizations identified in this notice and to any other consulting parties.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3004 and the implementing regulations, 43 CFR 10.9.

Dated: April 30, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–10157 Filed 5–8–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0037880; PPWOCRADN0–PCU00RP14.R50000]

Notice of Intended Repatriation: Oakland Museum of California, Oakland, CA

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Oakland Museum of California (OMCA) intends to repatriate certain cultural items that meet the definition of objects of cultural patrimony and that have a cultural affiliation with the Indian Tribes or Native Hawaiian organizations in this notice.

DATES: Repatriation of the cultural items in this notice may occur on or after June 10, 2024.

ADDRESSES: Anna Bunting, Oakland Museum of California, 1000 Oak Street, Oakland, CA 94607, telephone (510) 318–8493, email *nagpra@museumca.org.*

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the Oakland Museum of California, and additional information on the determinations in this notice, including the results of consultation, can be found in the summary or related records. The National Park Service is not responsible for the determinations in this notice.

Abstract of Information Available

A total of 259 cultural items or lots of items, represented by 188 catalog numbers, have been requested for repatriation. The 259 objects of cultural patrimony are 76 baskets, three rattles, nine awls, 12 yo-koli, two soap root brushes, seven lithics, six netted bags, one pictograph, one flute, one smoking pipe, one turtle charm, one singing bow, four gambling bones, four cooking sticks/tools, three meat drying poles, two fire drills, one root digger, one cloak, one ear ornament, three hair pins, two headnets, one headdress, one necklace, four tremblers, 18 magnesite beads, 31 acorn woodpecker scalps, and 63 lots or individual items of raw or processed natural materials (*i.e.* acorns and acorn meal; basket material; tumpline and cord; seeds, nuts and berries; eel meat, salmon eggs, grasshoppers, bark, medicinal roots, herbs, mushrooms, tobacco, deer sinew and brain, clam shell, maize).

All of the items on this claim were acquired by Charles P. Wilcomb during various 'collecting trips' that he undertook while he was the Curator of the Oakland Public Museum (OPM). All of the items requested for repatriation were donated to the OPM by either Charles P. Wilcomb, or by his daughter, Miss Louise Wilcomb, after his death in 1915. The Oakland Public Museum and its collections were merged into the Oakland Museum of California in 1969.

Twenty-four of the items were collected during Wilcomb's September 29–November 28, 1911, collecting trip. They were acquired by the Oakland Public Museum on December 11, 1911. Wilcomb collected these items from the following sources: Dr. Indian Jim's wife and Captain John Chinaman's wife in Bald Rock, Butte County; and Kittie George, Billy Williams, and an unnamed old woman at Camp Creek and Dogwood Rancheria, Butte County.

One hundred and fifty-four of the items were collected during Wilcomb's November 24–December 27, 1913 collecting trip. They were acquired by the Oakland Public Museum on January 7, 1914. Wilcomb collected these items from the following sources: Hood Smith's wife (Cleo Martin Smith), Johnny Johnson's wife (Cordelia Martin Johnson), and an unnamed old woman in Brush Creek, Butte Co.; Fanny Wagner, Old Woman Maggie, Rose Edward, an unnamed old woman, and an unnamed individual at Ed Wagner's Camp, Hunter's Ravine, Plumas Co.; John Kennedy at Middle Fork, Feather River, Butte Co.; Dick Harris and his wife (Emeline Harry) at Dick Harris camp, Beau Creek, Butte Co (Dick Harris- listed in OPM ledgers- is a misspelling of Dick Harry, and Beau Creek is a misspelling of Bean Creek); Henry Flinn at Bald Rock, Butte Co; An unnamed individual at Berry Creek, Butte Co.; From the old council house near Sulphur Springs, Berry Creek, Butte Co.

Eighty-one of the items were donated to the Oakland Public Museum on December 7, 1915 by Wilcomb's daughter, Louise Wilcomb, after her father's death in 1915. All of the items on this list were most likely collected sometime between 1911 and 1915 when Wilcomb was going on extensive collecting trips to Maidu ancestral territory. These items are noted as coming from the following locations: Brush Creek, Butte Co.; Bean Creek, Butte Co.; Buckshot Johnson at Dogwood Creek, Feather River Canyon, Butte Co.; Berry Creek, Butte Co. (including Bald Rock, Sulphur Springs, Beau Creek); Pulga, Feather River Canyon, Butte Co.; Hunter's Ravine, Butte Co; Stanfield Hill, Butte Co.; Billy Day camp, Sulphur Springs, Butte Co.; Big Meadows, Plumas Co.

Two of the items included in the 1915 acquisition do not have collection location information. One of these items is a rattle that is very similar to another rattle being requested for repatriation that came from Dick Harris's camp. OMCA institutional records note that these two rattles were most likely ''made by the same group of people, and perhaps by the same person.'' The other item with no collection location information is a lot of *Yo-Koli,* however, as this item was originally cataloged in 1915 using the Konkow name (*yo-koli*) it is assumed to have come from Butte County.

Information provided by the Tribe indicates that Berry Creek Rancheria of Maidu Indians of California is culturally affiliated with the items and places associated with this claim. In 2007, random testing of OMCA's basket collection was conducted using pXRF technology. Three baskets included in

this request for repatriation were tested at that time with positive results for mercury and negative results for arsenic. Two other baskets included on this request for repatriation were tested at that time, with negative results for both mercury and arsenic.

Determinations

The Oakland Museum of California has determined that:

- The 259 objects of cultural patrimony described in this notice have ongoing historical, traditional, or cultural importance central to the Native American group, including any constituent sub-group (such as a band, clan, lineage, ceremonial society, or other subdivision), according to the Native American traditional knowledge of an Indian Tribe or Native Hawaiian organization.
- There is a reasonable connection between the cultural items described in this notice and the Berry Creek Rancheria of Maidu Indians of California.

Requests for Repatriation

Additional, written requests for repatriation of the cultural items in this notice must be sent to the authorized representative identified in this notice under **ADDRESSES**. Requests for repatriation may be submitted by any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the cultural items in this notice to a requestor may occur on or after June 10, 2024. If competing requests for repatriation are received, the Oakland Museum of California must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the cultural items are considered a single request and not competing requests. The Oakland Museum of California is responsible for sending a copy of this notice to the Indian Tribes and Native Hawaiian organizations identified in this notice and to any other consulting parties.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3004 and the implementing regulations, 43 CFR 10.9.

Dated: April 30, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–10155 Filed 5–8–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0037883; PPWOCRADN0–PCU00RP14.R50000]

Notice of Intended Repatriation: Gilcrease Museum, Tulsa, OK

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Gilcrease Museum intends to repatriate a certain cultural item that meets the definition of a sacred object/object of cultural patrimony and that has a cultural affiliation with the Indian Tribes or Native Hawaiian organizations in this notice.

DATES: Repatriation of the cultural item in this notice may occur on or after June 10, 2024.

ADDRESSES: Laura Bryant, Gilcrease Museum, 800 S Tucker Drive, Tulsa, OK 74104, telephone (918) 596–2747, email *laura-bryant@utulsa.edu.*

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the Gilcrease Museum, and additional information on the determinations in this notice, including the results of consultation, can be found in the summary or related records. The National Park Service is not responsible for the determinations in this notice.

Abstract of Information Available

A total of one cultural item has been requested for repatriation. The one sacred object/object of cultural patrimony is a pipe stem. This stem is connected to Chief Walking Rain and was purchased by Frank Engles from Edward Payne's estate in Illinois. Thomas Gilcrease purchased Frank Engles's collection in 1950 and transferred his collection to the City of Tulsa's Gilcrease Museum in 1955.

Determinations

The Gilcrease Museum has determined that:

- The one sacred object/object of cultural patrimony described in this notice is, according to the Native American traditional knowledge of an Indian Tribe or Native Hawaiian organization, specific ceremonial objects needed by a traditional Native American religious leader for present-day adherents to practice traditional Native American religion, and have ongoing historical, traditional, or cultural importance central to the Native American group, including any constituent sub-group (such as a band, clan, lineage, ceremonial society, or other subdivision).
- There is a reasonable connection between the cultural item described in this notice and the Iowa Tribe of Kansas and Nebraska.

Requests for Repatriation

Additional, written requests for repatriation of the cultural item in this notice must be sent to the authorized representative identified in this notice under **ADDRESSES**. Requests for repatriation may be submitted by any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the cultural item in this notice to a requestor may occur on or after June 10, 2024. If competing requests for repatriation are received, the Gilcrease Museum must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the cultural item are considered a single request and not competing requests. The Gilcrease Museum is responsible for sending a copy of this notice to the Indian Tribes and Native Hawaiian organizations identified in this notice and to any other consulting parties.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3004 and the implementing regulations, 43 CFR 10.9.

Dated: April 30, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–10158 Filed 5–8–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0037885; PPWOCRADN0–PCU00RP14.R50000]

Notice of Intended Disposition: Arizona Army National Guard, Papago Park Miliary Reservation, Phoenix, AZ

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Arizona Army National Guard intends to carry out the disposition of human

remains, associated funerary objects, unassociated funerary objects, sacred objects, or objects of cultural patrimony removed from Federal or Tribal lands to the lineal descendants, Indian Tribe, or Native Hawaiian organization with priority for disposition in this notice.

DATES: Disposition of the human remains or cultural items in this notice may occur on or after June 10, 2024. If no claim for disposition is received by May 9, 2025, the human remains or cultural items in this notice will become unclaimed human remains or cultural items.

ADDRESSES: Shelby Manney, Deputy Environmental Programs Manager, Departments of the Army and the Air Force, Joint Force Headquarters-Arizona, Arizona Army National Guard, 5636 East McDowell Road, Phoenix, AZ 85008, telephone (602) 267–2740, email *manneys@emo.azdema.gov* and *shelby.a.manney.nfg@army.mil.*

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the Arizona Army National Guard, and additional information on the human remains or cultural items in this notice, including the results of consultation, can be found in the related records. The National Park Service is not responsible for the identifications in this notice.

Abstract of Information Available

Based on the information available, the one object of cultural patrimony is a ceramic bowl. On May 15, 2020, the object of cultural patrimony was removed from Papago Park Military Reservation located in Phoenix, Maricopa County, Arizona. During an archaeological site condition assessment, the object was found moved from its documented location by unknown persons. Due to the potential for theft or damage, in consultation with the Indian Tribes, the Arizona Army National Guard recovered and housed the object of cultural patrimony until final disposition.

Determinations

The Arizona Army National Guard has determined that:

- The one object of cultural patrimony described in this notice has ongoing historical, traditional, or cultural importance central to the Native American group, including any constituent sub-group (such as a band, clan, lineage, ceremonial society, or other subdivision), according to the Native American traditional knowledge of an Indian Tribe or Native Hawaiian organization.
- A relationship of shared group identity can be reasonably traced between the object of cultural patrimony and the Gila River Indian Community of the Gila River Indian Reservation, Arizona, and the Salt River Pima-Maricopa Indian Community of the Salt River Reservation, Arizona.

Claims for Disposition

Written claims for disposition of the human remains or cultural items in this notice must be sent to the appropriate official identified in this notice under **ADDRESSES**. If no claim for disposition is received by May 9, 2025, the human remains or cultural items in this notice will become unclaimed human remains or cultural items. Claims for disposition may be submitted by:

1. Any lineal descendant, Indian Tribe, or Native Hawaiian organization identified in this notice.
2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that they have priority for disposition.

Disposition of the human remains or cultural items in this notice may occur on or after June 10, 2024. If competing claims for disposition are received, the Arizona Army National Guard must determine the most appropriate claimant prior to disposition. Requests for joint disposition of the human remains or cultural items are considered a single request and not competing requests. The Arizona Army National Guard is responsible for sending a copy of this notice to the lineal descendants, Indian Tribes, and Native Hawaiian organizations identified in this notice and to any other consulting parties.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3002, and the implementing regulations, 43 CFR 10.7.

Dated: April 30, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–10160 Filed 5–8–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0037879; PPWOCRADN0–PCU00RP14.R50000]

Notice of Inventory Completion: Peabody Museum of Archaeology and Ethnology, Harvard University, Cambridge, MA

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Peabody Museum of Archaeology and Ethnology, Harvard University (PMAE) has completed an inventory of human remains and has determined that there is a cultural affiliation between the human remains and Indian Tribes or Native Hawaiian organizations in this notice. The human remains were collected at the Sherman Institute, Riverside County, CA.

DATES: Repatriation of the human remains in this notice may occur on or after June 10, 2024.

ADDRESSES: Jane Pickering, Peabody Museum of Archaeology and Ethnology, Harvard University, 11 Divinity Avenue, Cambridge, MA 02138, telephone (617) 496–2374, email *jpickering@fas.harvard.edu.*

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the PMAE, and additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records. The National Park Service is not responsible for the determinations in this notice.

Abstract of Information Available

Based on the information available, human remains representing, at minimum, one individual was collected at the Sherman Institute, Riverside County, CA. The human remains are hair clippings collected from one individual who was recorded as being 19 years old and identified as ''Puyallup.'' Samuel H. Gilliam took the hair clippings at the Sherman Institute between 1930 and 1933. Gilliam sent the hair clippings to George Woodbury, who donated the hair clippings to the PMAE in 1935. No associated funerary objects are present.

Cultural Affiliation

Based on the information available and the results of consultation, cultural affiliation is clearly identified by the information available about the human remains described in this notice.

Determinations

The PMAE has determined that:

- The human remains described in this notice represent the physical remains of one individual of Native American ancestry.
- There is a reasonable connection between the human remains described

in this notice and the Puyallup Tribe of the Puyallup Reservation.

Requests for Repatriation

Written requests for repatriation of the human remains in this notice must be sent to the Responsible Official identified in **ADDRESSES**. Requests for repatriation may be submitted by:

1. Any one or more of the Indian Tribes or Native Hawaiian organizations identified in this notice.

2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the human remains in this notice to a requestor may occur on or after June 10, 2024. If competing requests for repatriation are received, the PMAE must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the human remains are considered a single request and not competing requests. The PMAE is responsible for sending a copy of this notice to the Indian Tribe identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.10.

Dated: April 30, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–10154 Filed 5–8–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0037884; PPWOCRADN0–PCU00RP14.R50000]

Notice of Intended Repatriation: Gilcrease Museum, Tulsa, OK

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Gilcrease Museum intends to repatriate certain cultural items that meet the definition of unassociated funerary objects and that have a cultural affiliation with the Indian Tribes or Native Hawaiian organizations in this notice.

DATES: Repatriation of the cultural items in this notice may occur on or after June 10, 2024.

ADDRESSES: Laura Bryant, Gilcrease Museum, 800 S Tucker Drive, Tulsa, OK 74104, telephone (918) 596–2747, email *laura-bryant@utulsa.edu.*

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the Gilcrease Museum, and additional information on the determinations in this notice, including the results of consultation, can be found in the summary or related records. The National Park Service is not responsible for the determinations in this notice.

Abstract of Information Available

A total of 17 cultural items have been requested for repatriation. The 17 unassociated funerary objects are four lots of ceramic vessels, 11 lots of ceramic sherds and partially restored vessels, one lot of worked lithics, and one lot of gar scales. These were removed from the Banks Site in Crittenden County, AR by Frank Soday in the mid-20th century. The Soday collection was purchased by the Thomas Gilcrease Association and then donated to the Museum in 1982.

A total of two cultural items have been requested for repatriation. The two unassociated funerary objects are two lots of ceramic vessels. These were removed from the Cherry Valley site in Cross County, AR by Frank Soday in the mid-20th century.

A total of two cultural items have been requested for repatriation. The two unassociated funerary objects are one lot of ceramic vessels and one lot of worked shell, including ear plugs and gorget. These were removed from Rose Mound in Cross County, AR, by Dr. C.A. Self in 1936. Harry Lemley acquired the items from Dr. Self in 1936 and sold his collection to Thomas Gilcrease in 1955.

A total of two cultural items have been requested for repatriation. The two unassociated funerary objects are one lot of ceramic vessels and one lot of bone tools. These were removed from the Shawnee Village Site (3MS7) in Mississippi County, AR, by Carroll Snider, Dr. J.K. Hampson, and W.A. McKay. Harry Lemley acquired these items in 1932 and 1936 and sold his collection to Thomas Gilcrease in 1955.

A total of 30 cultural items have been requested for repatriation. The 30 unassociated funerary objects are two lots of ceramic vessels, 17 lots of sherds, one lot of daub, eight lots of worked lithics, one lot of ceramic pipe bowls and beads, and one lot of shell. These were removed from the Stott Site in Poinsett County, Arkansas likely by Elbert Hawkins in the 1970s.

Determinations

The Gilcrease Museum has determined that:

- The 53 unassociated funerary objects described in this notice are reasonably believed to have been placed intentionally with or near human remains, and are connected, either at the time of death or later as part of the death rite or ceremony of a Native American culture according to the Native American traditional knowledge of a lineal descendant, Indian Tribe, or Native Hawaiian organization. The unassociated funerary objects have been identified by a preponderance of the evidence as related to human remains, specific individuals, or families, or removed from a specific burial site or burial area of an individual or individuals with cultural affiliation to an Indian Tribe or Native Hawaiian organization.
- There is a reasonable connection between the cultural items described in this notice and the Quapaw Nation.

Requests for Repatriation

Additional, written requests for repatriation of the cultural items in this notice must be sent to the authorized representative identified in this notice under **ADDRESSES**. Requests for repatriation may be submitted by any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the cultural items in this notice to a requestor may occur on or after June 10, 2024. If competing requests for repatriation are received, the Gilcrease Museum must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the cultural items are considered a single request and not competing requests. The Gilcrease Museum is responsible for sending a copy of this notice to the Indian Tribes and Native Hawaiian organizations identified in this notice and to any other consulting parties.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3004 and the implementing regulations, 43 CFR 10.9.

Dated: April 30, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–10159 Filed 5–8–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0037878; PPWOCRADN0–PCU00RP14.R50000]

Notice of Inventory Completion: Peabody Museum of Archaeology and Ethnology, Harvard University, Cambridge, MA

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Peabody Museum of Archaeology and Ethnology, Harvard University (PMAE) has completed an inventory of human remains and has determined that there are known lineal descendants connected to the human remains in this notice.

DATES: Repatriation of the human remains in this notice may occur on or after June 10, 2024.

ADDRESSES: Jane Pickering, Peabody Museum of Archaeology and Ethnology, Harvard University, 11 Divinity Avenue, Cambridge, MA 02138, telephone (617) 496–2374, email *jpickering@fas.harvard.edu.*

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the PMAE, and additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records. The National Park Service is not responsible for the determinations in this notice.

Abstract of Information Available

Based on the information available, human remains representing one individual have been reasonably identified. The human remains were collected at the U.S. Indian Vocational School, Albuquerque, Bernalillo County, NM, and are hair clippings collected from one individual, Harrison Jackson, who was recorded as being 15 years old and identified as ''Walapai.'' Reuben Perry took the hair clippings at the U.S. Indian Vocational School between 1930 and 1933. Perry sent the hair clippings to George Woodbury, who donated the hair clippings to the PMAE in 1935. No associated funerary objects are present.

Lineal Descendant

Based on the information available and the results of consultation, a lineal descendant is connected to the human remains described in this notice.

Determinations

The PMAE has determined that:

- The human remains described in this notice represent the physical remains of one individual of Native American ancestry.
- Lucille J. Watahomigie is connected to the human remains described in this notice.

Requests for Repatriation

Written requests for repatriation of the human remains in this notice must be sent to the authorized representative identified in this notice under **ADDRESSES**. Requests for repatriation may be submitted by:

1. The known lineal descendant connected to the human remains.
2. Any other lineal descendant not identified who shows, by a preponderance of the evidence, that the requestor is a lineal descendant.

Repatriation of the human remains in this notice to a requestor may occur on or after June 10, 2024. If competing requests for repatriation are received, the PMAE must determine the most appropriate requestor prior to repatriation. The PMAE is responsible for sending a copy of this notice to the lineal descendant and any other consulting parties.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.10.

Dated: April 30, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–10153 Filed 5–8–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0037881; PPWOCRADN0–PCU00RP14.R50000]

Notice of Inventory Completion: California State University, Sacramento, Sacramento, CA

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the California State University, Sacramento has completed an inventory of human remains and associated funerary objects and has determined that there is a cultural affiliation between the human remains and associated funerary objects and Indian Tribes or Native Hawaiian organizations in this notice.

DATES: Repatriation of the human remains and associated funerary objects in this notice may occur on or after June 10, 2024.

ADDRESSES: Dr. Mark Wheeler, Senior Advisor to President Luke Wood, California State University, Sacramento, 6000 J Street, Sacramento, CA 95819, telephone (916) 460–0490, email *mark.wheeler@csus.edu.*

SUPPLEMENTARY INFORMATION: This notice is published as part of the National Park Service's administrative responsibilities under NAGPRA. The determinations in this notice are the sole responsibility of the California State University, Sacramento, and additional information on the determinations in this notice, including the results of consultation, can be found in the inventory or related records. The National Park Service is not responsible for the determinations in this notice.

Abstract of Information Available

In 1964–71, Stephen Humphreys, a student at Sacramento State College, conducted extensive surveys and excavations in the region between Oroville and Paradise in Butte County, California.

Human remains representing, at minimum, two individuals were removed from CA–BUT–301 (Kathy's Rockshelter). The 52,341 associated funerary objects from the site include baked clay objects; faunal and floral remains; flaked and ground stone objects; modified bone, shell, stone, and wood objects; basketry and cordage, thermally altered rock; quartz crystals; unmodified stones; pigment; historic materials (worked glass, buttons, beads and textiles), and soils.

Human remains representing, at minimum, three individuals were removed from CA–BUT–302 (Fox Site). The 4,324 associated funerary objects from the site include baked clay objects; faunal and floral remains; flaked and ground stone objects; modified bone, shell and stone; quartz crystals; unmodified stone; and soils.

Human remains representing, at minimum, four individuals were removed from CA–BUT–669 (Kendall's Rockshelter). The 4,754 associated funerary objects from the site include baked clay objects; faunal and floral remains; flaked and ground stone objects; modified bone, shell and stone; quartz crystals; unmodified stone; pigment; historic material (worked glass, buttons); and ash and soils. An unknown number of objects may be missing from the collection, and California State University, Sacramento continues to look for them.

Cultural Affiliation

Based on the information available and the results of consultation, cultural affiliation is clearly identified by the information available about the human remains and associated funerary objects described in this notice.

Determinations

The California State University, Sacramento has determined that:

- The human remains described in this notice represent the physical remains of nine individuals of Native American ancestry.
- The 61,419 objects described in this notice are reasonably believed to have been placed intentionally with or near individual human remains at the time of death or later as part of the death rite or ceremony.
- There is a reasonable connection between the human remains and associated funerary objects described in this notice and the Berry Creek Rancheria of Maidu Indians of California; Enterprise Rancheria of Maidu Indians of California; Greenville Rancheria; Mechoopda Indian Tribe of Chico Rancheria, California; and the Mooretown Rancheria of Maidu Indians of California.

Requests for Repatriation

Written requests for repatriation of the human remains and associated funerary objects in this notice must be sent to the authorized representative identified in this notice under **ADDRESSES**. Requests for repatriation may be submitted by:

1. Any one or more of the Indian Tribes or Native Hawaiian organizations identified in this notice.
2. Any lineal descendant, Indian Tribe, or Native Hawaiian organization not identified in this notice who shows, by a preponderance of the evidence, that the requestor is a lineal descendant or a culturally affiliated Indian Tribe or Native Hawaiian organization.

Repatriation of the human remains and associated funerary objects in this notice to a requestor may occur on or after June 10, 2024. If competing requests for repatriation are received, the California State University, Sacramento must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the human remains and associated funerary objects are considered a single request and not competing requests. The California State University, Sacramento is responsible for sending a copy of this notice to the Indian Tribes and Native Hawaiian organizations identified in this notice.

Authority: Native American Graves Protection and Repatriation Act, 25 U.S.C. 3003, and the implementing regulations, 43 CFR 10.10.

Dated: April 30, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–10156 Filed 5–8–24; 8:45 am]

BILLING CODE 4312–52–P

INTERNATIONAL TRADE COMMISSION

[USITC SE–24–018]

Sunshine Act Meetings

AGENCY HOLDING THE MEETING: United States International Trade Commission.

TIME AND DATE: May 16, 2024 at 9:30 a.m.

PLACE: Room 101, 500 E Street SW, Washington, DC 20436, Telephone: (202) 205–2000.

STATUS: Open to the public.

MATTERS TO BE CONSIDERED:

1. Agendas for future meetings: none.
2. Minutes.
3. Ratification List.
4. Commission vote on Inv. Nos. 701–TA–689 and 731–TA–1618 (Final) (Non-Refillable Steel Cylinders from India. The Commission currently is scheduled to complete and file its determination and views on May 28, 2024.
5. Outstanding action jackets: none.

CONTACT PERSON FOR MORE INFORMATION: Sharon Bellamy, Supervisory Hearings and Information Officer, 202–205–2000.

The Commission is holding the meeting under the Government in the Sunshine Act, 5 U.S.C. 552(b). In accordance with Commission policy, subject matter listed above, not disposed of at the scheduled meeting, may be carried over to the agenda of the following meeting.

By order of the Commission.

Issued: May 7, 2024.

Sharon Bellamy,

Supervisory Hearings and Information Officer.

[FR Doc. 2024–10261 Filed 5–7–24; 4:15 pm]

BILLING CODE 7020–02–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

[Docket No. DEA–1366]

Bulk Manufacturer of Controlled Substances Application: Curia New York, Inc.

AGENCY: Drug Enforcement Administration, Justice.

ACTION: Notice of application.

SUMMARY: Curia New York, Inc. has applied to be registered as a bulk manufacturer of basic class(es) of controlled substance(s). Refer to Supplementary Information listed below for further drug information.

DATES: Registered bulk manufacturers of the affected basic class(es), and applicants therefore, may submit electronic comments on or objections to the issuance of the proposed registration on or before July 8, 2024. Such persons may also file a written request for a hearing on the application on or before July 8, 2024.

ADDRESSES: The Drug Enforcement Administration requires that all comments be submitted electronically through the Federal eRulemaking Portal, which provides the ability to type short comments directly into the comment field on the web page or attach a file for lengthier comments. Please go to *https://www.regulations.gov* and follow the online instructions at that site for submitting comments. Upon submission of your comment, you will receive a Comment Tracking Number. Please be aware that submitted comments are not instantaneously available for public view on *https://www.regulations.gov*. If you have received a Comment Tracking Number, your comment has been successfully submitted and there is no need to resubmit the same comment.

SUPPLEMENTARY INFORMATION: In accordance with 21 CFR 1301.33(a), this is notice that on April 12, 2024, Curia New York, Inc., 33 Riverside Avenue, Rensselaer, New York 12144–2951, applied to be registered as a bulk manufacturer of the following basic class(es) of controlled substance(s):

Controlled substance	Drug code	Schedule
Gamma Hydroxybutyric Acid ..	2010	I

The company plans to manufacture the above controlled substances as bulk active pharmaceutical ingredients for use in product development and for distribution to its customers. No other activities for these drug codes are authorized for this registration.

Marsha Ikner,

Acting Deputy Assistant Administrator.

[FR Doc. 2024–10083 Filed 5–8–24; 8:45 am]

BILLING CODE P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

[Docket No. DEA–1367]

Bulk Manufacturer of Controlled Substances Application: Veranova, L.P.

AGENCY: Drug Enforcement Administration, Justice.

ACTION: Notice of application.

SUMMARY: Veranova, L.P. has applied to be registered as a bulk manufacturer of basic class(es) of controlled substance(s). Refer to Supplementary Information listed below for further drug information.

DATES: Registered bulk manufacturers of the affected basic class(es), and applicants therefore, may submit electronic comments on or objections to the issuance of the proposed registration on or before July 8, 2024. Such persons may also file a written request for a hearing on the application on or before July 8, 2024.

ADDRESSES: The Drug Enforcement Administration requires that all comments be submitted electronically through the Federal eRulemaking Portal, which provides the ability to type short comments directly into the comment field on the web page or attach a file for lengthier comments. Please go to *https://www.regulations.gov* and follow the online instructions at that site for submitting comments. Upon submission of your comment, you will receive a Comment Tracking Number. Please be aware that submitted comments are not instantaneously available for public view on *https://www.regulations.gov*. If you have received a Comment Tracking Number, your comment has been successfully submitted and there is no need to resubmit the same comment.

SUPPLEMENTARY INFORMATION: In accordance with 21 CFR 1301.33(a), this is notice that on April 8, 2024, Veranova, L.P., 2003 Nolte Drive, West Deptford, New Jersey 08066–1727, applied to be registered as a bulk manufacturer of the following basic class(es) of controlled substance(s):

Controlled substance	Drug code	Schedule
Gamma hydroxybutyric acid	2010	I
Marihuana	7360	I
Tetrahydrocannabinols	7370	I
3,4-Methylenedioxymethamphetamine	7405	I
Psilocybin	7437	I
Dihydromorphine	9145	I
Difenoxin	9168	I
Fentanyl related-substances	9850	I
Amphetamine	1100	II
Methamphetamine	1105	II
Lisdexamfetamine	1205	II
Methylphenidate	1724	II
Nabilone	7379	II
4-Anilino-N-Phenethyl-4-Piperidine (ANPP)	8333	II
Norfentanyl (N-phenyl-N-(piperidin-4-yl) propionamide)	8366	II
Cocaine	9041	II
Codeine	9050	II
Dihydrocodeine	9120	II
Oxycodone	9143	II
Hydromorphone	9150	II
Diphenoxylate	9170	II
Ecgonine	9180	II
Hydrocodone	9193	II
Levorphanol	9220	II
Meperidine	9230	II
Methadone	9250	II
Methadone intermediate	9254	II
Morphine	9300	II
Thebaine	9333	II
Opium tincture	9630	II
Oxymorphone	9652	II
Noroxymorphone	9668	II
Alfentanil	9737	II
Remifentanil	9739	II
Sufentanil	9740	II
Tapentadol	9780	II
Fentanyl	9801	II

The company plans to bulk manufacture the listed controlled substances for use as internal intermediates and for sale to its customers. No other activities for these drug codes are authorized for this registration.

Marsha L. Ikner,

Acting Deputy Assistant Administrator.

[FR Doc. 2024–10084 Filed 5–8–24; 8:45 am]

BILLING CODE P

DEPARTMENT OF LABOR

Employment and Training Administration

Agency Information Collection Activities; Comment Request; Unemployment Insurance (UI) Title XII Advances and Voluntary Repayment Process

ACTION: Notice.

SUMMARY: The Department of Labor's (DOL) Employment and Training Administration (ETA) is soliciting comments concerning a proposed extension for the authority to conduct the information collection request (ICR) titled, ''Unemployment Insurance (UI) Title XII Advances and Voluntary Repayment Process.'' This comment request is part of continuing Departmental efforts to reduce paperwork and respondent burden in accordance with the Paperwork Reduction Act of 1995 (PRA).

DATES: Consideration will be given to all written comments received by July 8, 2024.

ADDRESSES: A copy of this ICR with applicable supporting documentation, including a description of the likely respondents, proposed frequency of response, and estimated total burden, may be obtained free by contacting Joe Williams by telephone at (202) 693–2928 (this is not a toll-free number), or by email at *Williams.Joseph@dol.gov.* For persons with a hearing or speech disability who need assistance to use the telephone system, please dial 711 to access telecommunications relay services.

Submit written comments about, or requests for a copy of, this ICR by mail or courier to the U.S. Department of Labor, Employment and Training Administration, Office of Unemployment Insurance, Room S–4524, Constitution Avenue NW, Washington, DC 20210; by email: *Williams.Joseph@dol.gov*; or by fax (202) 693–3975.

FOR FURTHER INFORMATION CONTACT: Cynthia Greene by telephone at (202) 693–2724 (this is not a toll-free number) or by email at *Cynthia.Greene@dol.gov.*

SUPPLEMENTARY INFORMATION: DOL, as part of continuing efforts to reduce paperwork and respondent burden, conducts a pre-clearance consultation program to provide the general public and Federal agencies an opportunity to comment on proposed and/or continuing collections of information before submitting them to the Office of Management and Budget (OMB) for final approval. This program helps to ensure requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements can be properly assessed.

Title XII, section 1201 of the Social Security Act (SSA), 42 U.S.C. 1321, provides for advances to states from the Federal Unemployment Account (FUA). The law further outlines specific requirements to be met by a state requesting an advance:

- The Governor or designee must apply for the advance;
- The application must cover a three-month period and the Secretary of Labor (Secretary) must be furnished with estimates of the amounts needed in each month of the three-month period;
- The application must be made on such forms and shall contain such information and data (fiscal and otherwise) concerning the operation and administration of the state unemployment compensation law as the Secretary deems necessary or relevant to the performance of his or her duties under this title;
- The amount required by any state for the payment of compensation in any month shall be determined with due allowance for contingencies and taking into account all other amounts that will be available in the state's unemployment fund for the payment of compensation in such month; and
- The term ''compensation'' means cash benefits payable to individuals with respect to their unemployment exclusive of expenses of administration.

Section 1202 (a) of the SSA provides that the Governor of any state may at any time request that funds be transferred from the account of such state to the FUA in repayment of part or all of the balance of advances made to such state under section 1201. These applications and repayments may be requested by an individual designated for that authority in writing by the Governor. The SSA, sections 1201 and 1202(a), authorize this information collection.

This information collection is subject to the PRA. A Federal agency generally cannot conduct or sponsor a collection of information, and the public is generally not required to respond to an information collection, unless it is approved by OMB under the PRA and displays a currently valid OMB Control Number. In addition, notwithstanding any other provisions of law, no person shall generally be subject to penalty for failing to comply with a collection of information that does not display a valid Control Number. See 5 CFR 1320.5(a) and 1320.6.

Interested parties are encouraged to provide comments to the contact shown in the **ADDRESSES** section. Comments must be written to receive consideration, and they will be summarized and included in the request for OMB approval of the final ICR. In order to help ensure appropriate consideration, comments should mention OMB control number 1205–0199.

Submitted comments will also be a matter of public record for this ICR and posted on the internet, without redaction. DOL encourages commenters not to include personally identifiable information, confidential business data, or other sensitive statements/information in any comments.

DOL is particularly interested in comments that:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;
- Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, (*e.g.,* permitting electronic submission of responses).

Agency: DOL–ETA.

Type of Review: Extension without changes.

Title of Collection: Unemployment Insurance (UI) Title XII Advances and Voluntary Repayment Process.

Form: Not Applicable.

OMB Control Number: 1205–0199.

Affected Public: State Workforce Agencies.

Estimated Number of Respondents: 4.

Frequency: Varies.

Total Estimated Annual Responses: 4.

Estimated Average Time per Response: 1 hour.

Estimated Total Annual Burden Hours: 4 hours.

Total Estimated Annual Other Cost Burden: $0.

Authority: 44 U.S.C. 3506(c)(2)(A).

José Javier Rodríguez,

Assistant Secretary for Employment and Training, Labor.

[FR Doc. 2024–10069 Filed 5–8–24; 8:45 am]

BILLING CODE 4510–FW–P

DEPARTMENT OF LABOR

Employment and Training Administration

Agency Information Collection Activities; Comment Request; Characteristics of the Insured Unemployed

ACTION: Notice.

SUMMARY: The Department of Labor's (DOL) Employment and Training Administration (ETA) is soliciting comments concerning a proposed extension for the authority to conduct the information collection request (ICR) titled, ''Characteristics of the Insured Unemployed.'' This comment request is part of continuing Departmental efforts to reduce paperwork and respondent burden in accordance with the Paperwork Reduction Act of 1995 (PRA).

DATES: Consideration will be given to all written comments received by July 8, 2024.

ADDRESSES: A copy of this ICR with applicable supporting documentation, including a description of the likely respondents, proposed frequency of response, and estimated total burden, may be obtained free by contacting Rachel Beistel by telephone at 202–693–2736 (this is not a toll-free number) or by email at *beistel.rachel@dol.gov*. For persons with a hearing or speech disability who need assistance to use the telephone system, please dial 711 to access telecommunications relay services.

Submit written comments about, or requests for a copy of, this ICR by mail or courier to the U.S. Department of Labor, Employment and Training Administration, Office of Unemployment Insurance Room S–4519, 200 Constitution Ave NW, Washington, DC 20210; by email: *beistel.rachel@dol.gov*; or by fax 202–693–3975.

FOR FURTHER INFORMATION CONTACT: Rachel Beistel by telephone at 202–693–2736 (this is not a toll-free number) or by email at *beistel.rachel@dol.gov.*

SUPPLEMENTARY INFORMATION: DOL, as part of continuing efforts to reduce paperwork and respondent burden, conducts a pre-clearance consultation program to provide the general public and Federal agencies an opportunity to comment on proposed and/or continuing collections of information before submitting them to the Office of Management and Budget (OMB) for final approval. This program helps to ensure requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements can be properly assessed.

Section 303(a)(6) of the Social Security Act specifies that for State UI programs to be certified to receive administrative funding from the Federal government, the State's law must include provisions for ''making of such reports . . . as the Secretary of Labor may from time to time require, and compliance with such provisions as the Secretary may from time to time find necessary to assure the correctness and verification of such reports.'' DOL considers the proposed changes and updates to the ETA 203 report to be one of those ''provisions . . . necessary to assure the correctness and verification'' of the reports submitted by states. ETA is proposing changes to the ETA 203 to update and expand terms and definitions in the race and ethnicity categories to adhere to updated guidance/changes set out in the Office of Management and Budget's (OMB) Revisions to its Statistical Policy Directive No. 15: Standards for Maintaining, Collecting, and Presenting Federal Data on Race and Ethnicity,[1] which became effective on March 29, 2024. Also, adding ''Another Gender Identity/Non-binary/X'' as a response option will make the data collection consistent with the U.S. State Department's passport guidelines. These changes will capture characteristics that better reflect society and the UI population across demographic groups. For example, race and ethnicity will be combined into one question and reporting category to decrease confusion by respondents; a separate race and/or ethnicity category will be added (''Middle Eastern or North African''); and ''other'' will be removed from ''Native Hawaiian or Pacific Islander.'' In addition to collecting age, industry, and occupation information, the revised ETA 203 report would also collect information on a claimant's primary language, self-identified disability status, level of educational attainment, and base period wages. ETA proposes adding these categories to increase understanding of interactions between socio-economic characteristics and unemployment insurance receipt, and to inform state UI programs managers about possible needs in areas such as translation services. These categories and the specific terms proposed were identified after examining data studied, collected, or used by the U.S. Department of State, the U.S. Census Bureau, and Bureau of Labor Statistics. An individual's refusal to disclose claimant demographic information will *not* impact eligibility determinations. Also, any responses collected and information provided will be treated as confidential. This data will not be shared beyond aggregate reporting to ETA and any demographic information associated with a specific claimant or employer will be masked or hidden from state agency staff. Furthermore, disclosure of demographic information is voluntary and a non-response to questions will continue to be reported as ''Information Not Available'' or INA.

The Government Performance and Results Act of 1993 (GPRA) requires Federal agencies to develop annual and strategic performance plans that establish performance goals, have concrete indicators of the extent that goals are achieved, and set performance targets. Each year, the agency is to issue a report that ''evaluate[s] the performance plan for the current fiscal year relative to the performance achieved toward the performance goals in the fiscal year covered by the report.'' DOL emphasizes the importance of complete and accurate information for program monitoring and improving program performance ''. . . as a framework for agencies to communicate progress in achieving their missions.'' (OMB Circular A–11, Section 15.5). The Social Security Act, Section 303(a)(6), authorizes this information collection.

This information collection is subject to the PRA. A Federal agency generally cannot conduct or sponsor a collection of information, and the public is generally not required to respond to an information collection, unless it is approved by OMB under the PRA and displays a currently valid OMB Control Number. In addition, notwithstanding any other provisions of law, no person shall generally be subject to penalty for failing to comply with a collection of information that does not display a valid Control Number. *See* 5 CFR 1320.5(a) and 1320.6.

Interested parties are encouraged to provide comments to the contact shown in the **ADDRESSES** section. Comments must be written to receive consideration, and they will be summarized and included in the request for OMB approval of the final ICR. In

[1] *https://www.govinfo.gov/content/pkg/FR-2024-03-29/pdf/2024-06469.pdf.*

order to help ensure appropriate consideration, comments should mention OMB control number 1205–0009.

Submitted comments will also be a matter of public record for this ICR and posted on the internet, without redaction. DOL encourages commenters not to include personally identifiable information, confidential business data, or other sensitive statements/information in any comments.

DOL is particularly interested in comments that:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;
- Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, (*e.g.,* permitting electronic submission of responses).

Agency: DOL–ETA.

Type of Review: Revision.

Title of Collection: Characteristics of the Insured Unemployed.

Form: ETA 203.

OMB Control Number: 1205–0009.

Affected Public: State Workforce Agencies.

Estimated Number of Respondents: 53.

Frequency: Monthly.

Total Estimated Annual Responses: 636.

Estimated Average Time per Response: 40 minutes.

Estimated Total Annual Burden Hours: 424 hours.

Total Estimated Annual Other Cost Burden: $0.

Authority: 44 U.S.C. 3506(c)(2)(A).

José Javier Rodríguez,

Assistant Secretary for Employment and Training, Labor.

[FR Doc. 2024–10071 Filed 5–8–24; 8:45 am]

BILLING CODE 4510–FW–P

DEPARTMENT OF LABOR

Employment and Training Administration

Program Year (PY) 2024 Workforce Innovation and Opportunity Act (WIOA) Title I Allotments; PY 2024 Title III Wagner-Peyser Act Employment Service Allotments and PY 2024 Workforce Information Grants

AGENCY: Employment and Training Administration, Labor.

ACTION: Notice.

SUMMARY: This notice announces allotments for PY 2024 for WIOA Title I Youth, Adult, and Dislocated Worker Activities programs; allotments for Employment Service (ES) activities under the Wagner-Peyser Act for PY 2024, and the allotments of Workforce Information Grants to States for PY 2024. WIOA allotments for states and the state allotments for the Wagner-Peyser Act ES are based on formulas defined in their respective statutes. WIOA requires allotments for the Outlying Areas to be competitively awarded rather than based on a formula determined by the Secretary of Labor (Secretary) as occurred under the Workforce Investment Act (WIA). However, for PY 2024, the Further Consolidated Appropriations Act, 2024 waives the competition requirement, and the Secretary is using the discretionary formula rationale and methodology for allocating PY 2024 funds for the Outlying Areas (American Samoa, Guam, the Commonwealth of the Northern Mariana Islands, the Republic of Palau, and the United States Virgin Islands) that was published in the **Federal Register** (Feb. 17, 2000). WIOA specifically included the Republic of Palau as an Outlying Area, except during any period for which the Secretary of Labor and the Secretary of Education determine that a Compact of Free Association is in effect and contains provisions for training and education assistance prohibiting the assistance provided under WIOA; no such determinations prohibiting assistance have been made. The formula that the Department of Labor (Department) used for PY 2024 is the same formula used in PY 2023 and is described in the section on Youth Activities program allotments. The Department invites comments only on the formula used to allot funds to the Outlying Areas.

DATES: The Department must receive comments on the formula used to allot funds to the Outlying Areas by June 10, 2024.

ADDRESSES: Questions on this notice can be submitted to the Employment and Training Administration, Office of Workforce Investment, 200 Constitution Ave. NW, Room S4209, Washington, DC 20210, Attention: Heather Fleck, Unit Chief, (202) 693–2956. Heather Fleck's email is *Fleck.Heather@dol.gov.* If you are deaf, hard of hearing, or have a speech disability, please dial 7–1–1 to access telecommunications relay services.

Commenters are advised that mail delivery in the Washington area may be delayed due to security concerns. The Department will receive hand-delivered comments at the above address. All overnight mail will be considered hand-delivered and must be received at the designated place by the date specified above. Please be advised that there may be a delay between when the mail is delivered to the building and when the relevant person receives it.

Comments: The Department will retain all comments on this notice and will release them upon request via email to any member of the public. The Department also will make all the comments it receives available for public inspection by appointment during normal business hours at the above address. If you need assistance to review the comments, the Department will provide you with appropriate aids such as readers or print magnifiers. The Department will make copies of this notice available, upon request, in large print, Braille, and electronic file. The Department also will consider providing the notice in other formats upon request. To schedule an appointment to review the comments and/or obtain the notice in an alternative format, contact Ms. Fleck using the information provided above. The Department will retain all comments received without making any changes to the comments, including any personal information provided. The Department therefore cautions commenters not to include their personal information such as Social Security Numbers, personal addresses, telephone numbers, and email addresses in their comments; this information would be released with the comment if the comments are requested. It is the commenter's responsibility to safeguard his or her information.

FOR FURTHER INFORMATION CONTACT: WIOA Youth Activities allotments—Sara Hastings at (202) 693–3599; WIOA Adult and Dislocated Worker Activities and ES allotments—Heather Fleck at (202) 693–2956; Workforce Information Grant allotments—Donald Haughton at (202) 693–2784. If you are deaf, hard of hearing, or have a speech disability,

please dial 7–1–1 to access telecommunications relay services.

SUPPLEMENTARY INFORMATION: The Department is announcing WIOA allotments for PY 2024 for Youth Activities, Adult and Dislocated Worker Activities, Wagner-Peyser Act PY 2024 allotments, and PY 2024 Workforce Information Grant allotments. This notice provides information on the amount of funds available during PY 2024 to states with an approved WIOA Combined or Unified State Plan, and information regarding allotments to the Outlying Areas.

On March 23, 2024, the Further Consolidated Appropriations Act, 2024, Pub. L. 118–47 was signed into law (''the Act''). The Act, Division D, title I, sections 106(b) and 107 of the Act allows the Secretary of Labor (Secretary) to set aside up to 0.5 percent of each discretionary appropriation for activities related to program integrity and 0.75 percent of most operating funds for evaluations. For 2024, as authorized by the Act, the Department has set aside $8,322,000 of the Training and Employment Services (TES) and $2,190,000 of the State Unemployment Insurance and Employment Services Operations (SUIESO) appropriations impacted in this FRN for these activities. ETA reserved these funds from the WIOA Adult, Youth, Dislocated Worker, Wagner-Peyser Act Employment Service, and Workforce Information Grant program budgets. Any funds not utilized for these reserve activities will be provided to the states. We also have attached tables listing the PY 2024 allotments for programs under WIOA Title I Youth Activities (Table A), Adult and Dislocated Workers Employment and Training Activities (Tables B and C, respectively), and the PY 2024 Wagner-Peyser Act allotments (Table D). We also have attached the PY 2024 Workforce Information Grant table (Table E) and the total WIOA Youth, Adult and Dislocated Worker funding for Outlying Areas (Table F).

Youth Activities Allotments. The appropriated level for PY 2024 for WIOA Youth Activities totals $948,130,000. After reducing the appropriation by $3,131,000 for set asides authorized by the Act and reserving $925,200 for Migrant and Seasonal Farmworker (MSFW) Youth, $944,073,800 is available for Youth Activities. Table A includes a breakdown of the Youth Activities program allotments for PY 2024 and provides a comparison of these allotments to PY 2023 Youth Activities allotments for all States and Outlying Areas. The WIOA Youth formula has a section in WIOA for a reservation for Migrant and Seasonal Farmworker (MSFW) Youth if the appropriation exceeds $925,000,000. Per WIOA 127(a)(1), ETA reserved 4 percent ($925,200) of the excess amount for MSFW Youth. For the Native American Youth program, the total amount available is 1.5 percent of the total amount for Youth Activities (after set asides authorized by the Act) after the MSFW Youth reservation (in accordance with WIOA section 127). The total funding available for the Outlying Areas was reserved at 0.25 percent of the amount appropriated for Youth Activities (after set asides authorized by the Act) after the amount reserved for MSFW Youth and Native American Youth (in accordance with WIOA section 127(b)(1)(B)(i)). On December 17, 2003, Pub. L. 108–188, the Compact of Free Association Amendments Act of 2003 (''the Compact''), was signed into law. The Compact specified that the Republic of Palau remained eligible for WIA Title I funding. See 48 U.S.C 1921d(f)(1)(B)(ix). WIOA sec. 512(g)(1) updated the Compact to refer to WIOA funding. The National Defense Authorization Act for Fiscal Year 2018 (Division A, Title XII, subtitle F, section 1259C(c) of Pub. L. 115–91) authorized WIOA Title I funding to the Republic of Palau through FY 2024.

Under WIA, the Secretary had discretion for determining the methodology for distributing funds to all Outlying Areas. Under WIOA the Secretary must award the funds through a competitive process. However, for PY 2024, the Further Consolidated Appropriations Act, 2024 waives the competition requirement regarding funding to Outlying Areas (*e.g.,* American Samoa, Guam, the Commonwealth of the Northern Mariana Islands, the Republic of Palau, and the United States Virgin Islands). For PY 2024, the Department used the same methodology used since PY 2000 (*i.e.,* we distribute funds among the Outlying Areas by formula based on relative share of the number of unemployed, a minimum of 90 percent of the prior year allotment percentage, a $75,000 minimum, and a 130 percent stop gain of the prior year share). For the relative share calculation in PY 2024, the Department continued to use the data obtained from the 2020 Census for American Samoa, Guam, the Commonwealth of the Northern Mariana Islands, and the United States Virgin Islands. For the Republic of Palau, the Department used data from Palau's 2020 Census. The Department will accept comments on this methodology. The Act additionally allows Outlying Areas to submit a single application according to the requirements established by the Secretary for a consolidated grant for Adult, Youth, and Dislocated Worker funds. Subject to approval of the grant application and other reporting requirements of the Secretary, the Act allows Outlying Areas receiving a consolidated grant to use those funds interchangeably between Adult, Youth, and Dislocated Worker programs or activities. Table F includes the total Youth, Adult and Dislocated Worker funding for Outlying Areas.

After the Department calculated the amount for the MSFW Youth, Outlying Areas and the Native American program, the amount available for PY 2024 allotments to the states is $927,587,911. This total amount is below the required $1 billion threshold specified in WIOA sec. 127(b)(1)(C)(iv)(IV); therefore, the Department did not apply the WIOA additional minimum provisions. Instead, as required by WIOA, the minimums of 90 percent of the prior year allotment percentage and 0.25 percent state minimum floor apply. WIOA also provides that no state may receive an allotment that is more than 130 percent of the allotment percentage for the state for the previous year. The three data factors required by WIOA sec. 127(b)(1)(C)(ii) for the PY 2024 Youth Activities state formula allotments are, summarized slightly, as follows:

(1) The average number of unemployed individuals in Areas of Substantial Unemployment (ASUs) for the 12-month period, July 2022–June 2023 in each state compared to the total number of unemployed individuals in ASUs in all states;

(2) Number of excess unemployed individuals or excess unemployed individuals in ASUs (depending on which is higher) averages for the same 12-month period used for ASU unemployed data compared to the total excess unemployed individuals or ASU excess number in all states; and

(3) Number of disadvantaged youth (age 16 to 21, excluding college students not in the workforce and military) from special tabulations of data from the American Community Survey (ACS), which the Department obtained from the Census Bureau in each state compared to the total number of disadvantaged youth in all states. ETA obtained updated data for use in PY 2023 and the same data was used in PY 2024. The Census Bureau collected the data used in the special tabulations for disadvantaged youth between January 1, 2016–December 31, 2020.

For purposes of identifying ASUs for the Youth Activities allotment formula, the Department continued to use the data made available by BLS (as described in the Local Area Unemployment Statistics (LAUS) Technical Memorandum No. S–23–12). For purposes of determining the number of disadvantaged youth, the Department used the special tabulations of ACS data available at: *https://www.dol.gov/agencies/eta/budget/formula/disadvantagedyouthadults.* See TEGL No. 01–23 for further information.

Adult Employment and Training Activities Allotments. The total appropriated funds for Adult Activities in PY 2024 is $885,649,000. After reducing the appropriated amount by $2,351,000 for set asides authorized by the Act, $883,298,000 remains for Adult Activities, of which $881,089,755 is for states and $2,208,245 is for Outlying Areas. Table B shows the PY 2024 Adult Employment and Training Activities allotments and a state-by-state comparison of the PY 2024 allotments to PY 2023 allotments.

In accordance with WIOA, the Department reserved the total available for the Outlying Areas at 0.25 percent of the full amount appropriated for Adult Activities (after set asides authorized by the Act). As discussed in the Youth Activities section above, in PY 2024 the Department will distribute the Adult Activities funding for the Outlying Areas, using the same principles, formula, and data as used for outlying areas for Youth Activities. The Department will accept comments on this methodology. After determining the amount for the Outlying Areas, the Department used the statutory formula to distribute the remaining amount available for allotments to the states. The Department did not apply the WIOA minimum provisions for the PY 2024 allotments because the total amount available for the states was below the $960 million threshold required for Adult Activities in WIOA sec. 132(b)(1)(B)(iv)(IV). Instead, as required by WIOA, the minimums of 90 percent of the prior year allotment percentage and 0.25 percent state minimum floor apply. WIOA also provides that no state may receive an allotment that is more than 130 percent of the allotment percentage for the state for the previous year. The three formula data factors for the Adult Activities program are the same as those used for the Youth Activities formula, except the Department used data for the number of disadvantaged adults (age 22 to 72, excluding college students not in the workforce and military).

Dislocated Worker Employment and Training Activities Allotments. The amount appropriated for Dislocated Worker activities in PY 2024 totals $1,396,412,000. The total appropriation includes formula funds for the states, while the National Reserve is used for National Dislocated Worker Grants, technical assistance and training, demonstration projects, Workforce Opportunity for Rural Communities, Community College Grants, and the Outlying Areas' Dislocated Worker allotments. After reducing the appropriated amount by $2,840,000 for set asides authorized by the Act, a total of $1,393,572,000 remains available for Dislocated Worker activities. The amount available for Outlying Areas is $3,483,930, leaving $297,375,070 for the National Reserve and a total of $1,092,713,000 available for states. Table C shows the PY 2024 Dislocated Worker activities allotments and a state-by-state comparison of the PY 2024 allotments to PY 2023 allotments.

Similar to the Adult Activities program, the Department reserved the total available for the Outlying Areas at 0.25 percent of the full amount appropriated for Dislocated Worker Activities (after set asides authorized by the Act). Similar to Youth and Adult funds, instead of competition, in PY 2024 the Department will use the same *pro rata* share as the areas received for the PY 2024 WIOA Adult Activities program to distribute the Outlying Areas' Dislocated Worker funds, the same methodology used in PY 2023. The Department will accept comments on this methodology.

The three data factors required in WIOA sec. 132(b)(2)(B)(ii) for the PY 2024 Dislocated Worker state formula allotments are, summarized slightly, as follows:

(1) Relative number of unemployed individuals in each state, compared to the total number of unemployed individuals in all states, for the 12-month period, October 2022–September 2023;

(2) Relative number of excess unemployed individuals in each state, compared to the total excess number of unemployed individuals in all states, for the 12-month period, October 2022–September 2023; and

(3) Relative number of long-term unemployed individuals in each state, compared to the total number of long-term unemployed individuals in all states, for the 12-month period, October 2022–September 2023.

In PY 2024, under WIOA the Dislocated Worker formula uses minimum and maximum provisions. No state may receive an allotment that is less than 90 percent of the state's prior year allotment percentage (stop loss) or more than 130 percent of the state's prior year allotment percentage (stop gain).

Wagner-Peyser Act ES Allotments. The appropriated level for PY 2024 for ES grants totals $675,052,000. After reducing the appropriated amount by $2,159,000 for set asides authorized by the Act, $672,893,000 is available for ES grants. After determining the funding for Guam and the United States Virgin Islands, the Department calculated allotments to states using the formula set forth at section 6 of the Wagner-Peyser Act (29 U.S.C. 49e). The Department based PY 2024 formula allotments on each state's share of calendar year 2023 monthly averages of the civilian labor force (CLF) and unemployment. Section 6(b)(4) of the Wagner-Peyser Act requires the Secretary to set aside up to three percent of the total funds available for ES to ensure that each state will have sufficient resources to maintain statewide ES activities. In accordance with this provision, the Department included the three percent set aside funds in this total allotment. The Department distributed the set-aside funds in two steps to states that have experienced a reduction in their relative share of the total resources available this year from their relative share of the total resources available the previous year. In Step 1, states that have a CLF below one million and are also below the median CLF density were maintained at 100 percent of their relative share of prior year resources. ETA calculated the median CLF density based on CLF data provided by the BLS for calendar year 2023. The Department distributed all remaining set-aside funds on a *pro-rata* basis in Step 2 to all other states experiencing reductions in relative share from the prior year but not meeting the size and density criteria for Step 1. The distribution of ES funds (Table D) includes $671,252,721 for states, as well as $1,640,279 for Outlying Areas.

Section 7(a) of the Wagner-Peyser Act (49 U.S.C. 49f(a)) authorizes states to use 90 percent of funds allotted to a state for labor exchange services and other career services such as job search and placement services to job seekers; appropriate recruitment services for employers; program evaluations; developing and providing labor market and occupational information; developing management information systems; and administering the work test for unemployment insurance claimants. Section 7(b) of the Wagner-Peyser Act states that 10 percent of the

total sums allotted to each state must be reserved for use by the Governor to provide performance incentives for public ES offices and programs, provide services for groups with special needs, and to provide for the extra costs of exemplary models for delivering services of the type described in section 7(a) and models for enhancing professional development and career advancement opportunities of state agency staff.

To provide services such as outreach to MSFWs, State Monitor Advocate (SMA) responsibilities, and others, State Workforce Agencies, (SWAs) must use Wagner-Peyser Act ES funding to provide employment services to migrant and seasonal farmworkers (MSFW), which are described at 20 CFR 651, 653, 654, and 658.

Workforce Information Grants Allotments. Total PY 2024 funding for Workforce Information Grants allotments to states is $32,000,000. After reducing the total by $31,000 for set asides authorized by the Act, $31,969,000 is available for Workforce Information Grants. Table E contains the allotment figures for each state and Outlying Area. The Department distributes the funds by administrative formula, with a reserve of $176,726 for Guam and the United States Virgin Islands. Guam and the United States Virgin Islands allotment amounts are partially based on CLF data. The Department distributes the remaining funds to the states with 40 percent distributed equally to all states and 60 percent distributed based on each state's share of CLF for the 12 months ending September 2023.

TABLE A—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WIOA YOUTH ACTIVITIES STATE ALLOTMENTS COMPARISON OF PY 2024 ALLOTMENTS VS PY 2023 ALLOTMENTS

State	PY 2023	PY 2024	Difference	% Difference
Total	$943,575,800	$944,073,800	$498,000	0.05
Alabama	10,411,891	9,375,648	(1,036,243)	−9.95
Alaska	3,824,865	3,444,195	(380,670)	−9.95
Arizona	25,423,422	22,893,156	(2,530,266)	−9.95
Arkansas	5,543,794	5,253,909	(289,885)	−5.23
California	142,969,572	146,040,343	3,070,771	2.15
Colorado	12,528,434	11,281,542	(1,246,892)	−9.95
Connecticut	12,065,981	10,865,114	(1,200,867)	−9.95
Delaware	2,959,957	3,525,562	565,605	19.11
District of Columbia	3,859,211	4,090,376	231,165	5.99
Florida	39,224,930	35,321,069	(3,903,861)	−9.95
Georgia	15,912,317	15,822,523	(89,794)	−0.56
Hawaii	3,760,088	3,385,865	(374,223)	−9.95
Idaho	2,358,998	2,366,901	7,903	0.34
Illinois	43,578,256	49,301,027	5,722,771	13.13
Indiana	14,093,876	14,430,689	336,813	2.39
Iowa	5,652,031	5,089,513	(562,518)	−9.95
Kansas	4,551,053	4,670,333	119,280	2.62
Kentucky	12,961,971	14,858,922	1,896,951	14.63
Louisiana	14,121,001	12,996,041	(1,124,960)	−7.97
Maine	2,821,164	2,540,388	(280,776)	−9.95
Maryland	18,022,572	16,228,876	(1,793,696)	−9.95
Massachusetts	21,018,238	18,926,398	(2,091,840)	−9.95
Michigan	34,408,717	34,257,716	(151,001)	−0.44
Minnesota	9,597,650	8,642,444	(955,206)	−9.95
Mississippi	9,566,263	8,614,181	(952,082)	−9.95
Missouri	11,203,397	10,088,379	(1,115,018)	−9.95
Montana	2,317,747	2,318,970	1,223	0.05
Nebraska	2,673,645	2,787,681	114,036	4.27
Nevada	10,809,613	14,059,914	3,250,301	30.07
New Hampshire	2,440,587	2,318,970	(121,617)	−4.98
New Jersey	26,580,977	23,935,505	(2,645,472)	−9.95
New Mexico	8,661,716	7,799,659	(862,057)	−9.95
New York	71,279,759	68,357,497	(2,922,262)	−4.10
North Carolina	24,201,171	27,096,137	2,894,966	11.96
North Dakota	2,317,747	2,318,970	1,223	0.05
Ohio	34,281,322	37,831,696	3,550,374	10.36
Oklahoma	6,876,800	6,192,386	(684,414)	−9.95
Oregon	9,505,398	12,363,539	2,858,141	30.07
Pennsylvania	42,912,756	43,332,595	419,839	0.98
Puerto Rico	21,554,940	19,409,685	(2,145,255)	−9.95
Rhode Island	3,321,932	2,991,317	(330,615)	−9.95
South Carolina	9,325,293	8,960,487	(364,806)	−3.91
South Dakota	2,317,747	2,318,970	1,223	0.05
Tennessee	14,138,571	14,716,454	577,883	4.09
Texas	91,789,734	96,383,731	4,593,997	5.00
Utah	3,512,938	3,273,389	(239,549)	−6.82
Vermont	2,317,747	2,318,970	1,223	0.05
Virginia	14,550,947	13,102,764	(1,448,183)	−9.95
Washington	19,134,328	22,795,157	3,660,829	19.13
West Virginia	5,499,645	4,952,293	(547,352)	−9.95
Wisconsin	10,018,152	9,021,095	(997,057)	−9.95
Wyoming	2,317,747	2,318,970	1,223	0.05

TABLE A—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WIOA YOUTH ACTIVITIES STATE ALLOTMENTS COMPARISON OF PY 2024 ALLOTMENTS VS PY 2023 ALLOTMENTS—Continued

State	PY 2023	PY 2024	Difference	% Difference
State Total	927,098,608	927,587,911	489,303	0.05
American Samoa	322,923	335,753	12,830	3.97
Guam	886,216	921,426	35,210	3.97
Northern Marianas	414,942	430,280	15,338	3.70
Palau	75,000	75,000	0	0.00
Virgin Islands	624,474	562,323	(62,151)	−9.95
Outlying Areas Total	2,323,555	2,324,782	1,227	0.05
Native Americans	14,153,637	14,161,107	7,470	0.05

TABLE B—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WIOA ADULT ACTIVITIES STATE ALLOTMENTS COMPARISON OF PY 2024 ALLOTMENTS VS PY 2023 ALLOTMENTS

State	PY 2023	PY 2024	Difference	% Difference
Total	$882,925,000	$883,298,000	$373,000	0.04
Alabama	10,103,726	9,097,195	(1,006,531)	−9.96
Alaska	3,592,966	3,235,035	(357,931)	−9.96
Arizona	24,088,343	21,688,667	(2,399,676)	−9.96
Arkansas	5,361,433	5,096,827	(264,606)	−4.94
California	137,974,143	141,158,847	3,184,704	2.31
Colorado	11,389,512	10,254,891	(1,134,621)	−9.96
Connecticut	10,953,250	9,862,090	(1,091,160)	−9.96
Delaware	2,853,613	3,396,064	542,451	19.01
District of Columbia	3,499,134	3,702,153	203,019	5.80
Florida	40,126,592	36,129,189	(3,997,403)	−9.96
Georgia	15,275,638	15,139,316	(136,322)	−0.89
Hawaii	3,803,223	3,424,347	(378,876)	−9.96
Idaho	2,201,794	2,202,724	930	0.04
Illinois	41,284,587	46,792,452	5,507,865	13.34
Indiana	12,955,282	12,605,374	(349,908)	−2.70
Iowa	4,080,702	3,674,183	(406,519)	−9.96
Kansas	3,861,076	3,476,436	(384,640)	−9.96
Kentucky	12,635,450	14,461,637	1,826,187	14.45
Louisiana	13,875,218	12,836,147	(1,039,071)	−7.49
Maine	2,591,045	2,332,926	(258,119)	−9.96
Maryland	17,396,744	15,663,684	(1,733,060)	−9.96
Massachusetts	18,040,385	16,243,206	(1,797,179)	−9.96
Michigan	31,989,992	31,901,181	(88,811)	−0.28
Minnesota	8,120,707	7,311,724	(808,983)	−9.96
Mississippi	9,171,420	8,257,765	(913,655)	−9.96
Missouri	10,386,320	9,351,637	(1,034,683)	−9.96
Montana	2,201,794	2,202,724	930	0.04
Nebraska	2,201,794	2,202,724	930	0.04
Nevada	10,557,658	13,730,754	3,173,096	30.05
New Hampshire	2,318,490	2,202,724	(115,766)	−4.99
New Jersey	25,950,239	23,365,082	(2,585,157)	−9.96
New Mexico	8,347,447	7,515,876	(831,571)	−9.96
New York	69,333,637	66,698,940	(2,634,697)	−3.80
North Carolina	22,972,996	25,763,380	2,790,384	12.15
North Dakota	2,201,794	2,202,724	930	0.04
Ohio	31,949,569	35,199,578	3,250,009	10.17
Oklahoma	6,515,962	5,866,843	(649,119)	−9.96
Oregon	9,259,978	12,043,057	2,783,079	30.05
Pennsylvania	39,877,363	40,343,724	466,361	1.17
Puerto Rico	22,385,642	20,155,589	(2,230,053)	−9.96
Rhode Island	2,871,414	2,585,364	(286,050)	−9.96
South Carolina	9,001,080	8,672,410	(328,670)	−3.65
South Dakota	2,201,794	2,202,724	930	0.04
Tennessee	13,853,614	14,430,633	577,019	4.17
Texas	86,292,577	90,806,962	4,514,385	5.23
Utah	2,737,000	2,464,341	(272,659)	−9.96
Vermont	2,201,794	2,202,724	930	0.04
Virginia	13,604,402	12,249,134	(1,355,268)	−9.96
Washington	18,038,932	21,854,025	3,815,093	21.15
West Virginia	5,382,213	4,846,038	(536,175)	−9.96
Wisconsin	8,644,415	7,783,260	(861,155)	−9.96

TABLE B—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WIOA ADULT ACTIVITIES STATE ALLOTMENTS COMPARISON OF PY 2024 ALLOTMENTS VS PY 2023 ALLOTMENTS—Continued

State	PY 2023	PY 2024	Difference	% Difference
Wyoming	2,201,794	2,202,724	930	0.04
State Total	880,717,687	881,089,755	372,068	0.04
American Samoa	306,253	318,370	12,117	3.96
Guam	840,469	873,724	33,255	3.96
Northern Marianas	393,455	408,004	14,549	3.70
Palau	75,000	75,000	0	0.00
Virgin Islands	592,136	533,147	(58,989)	−9.96
Outlying Areas Total	2,207,313	2,208,245	932	0.04

TABLE C—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WIOA DISLOCATED WORKER ACTIVITIES STATE ALLOTMENTS COMPARISON OF PY 2024 ALLOTMENTS VS PY 2023 ALLOTMENTS

State	PY 2023	PY 2024	Difference	% Difference
Total	$1,417,357,000	$1,393,572,000	($23,785,000)	−1.68
Alabama	13,164,128	12,337,631	(826,497)	−6.28
Alaska	6,376,097	5,876,555	(499,542)	−7.83
Arizona	30,156,226	28,315,755	(1,840,471)	−6.10
Arkansas	4,589,216	4,522,192	(67,024)	−1.46
California	158,397,875	158,507,519	109,644	0.07
Colorado	14,671,719	14,090,453	(581,266)	−3.96
Connecticut	12,320,319	11,806,402	(513,917)	−4.17
Delaware	2,561,280	2,517,108	(44,172)	−1.72
District of Columbia	12,150,262	12,090,836	(59,426)	−0.49
Florida	42,843,586	41,440,429	(1,403,157)	−3.28
Georgia	27,915,478	26,713,274	(1,202,204)	−4.31
Hawaii	2,556,829	2,534,139	(22,690)	−0.89
Idaho	2,007,847	2,611,276	603,429	30.05
Illinois	61,967,225	58,810,914	(3,156,311)	−5.09
Indiana	12,498,913	12,352,607	(146,306)	−1.17
Iowa	4,124,399	5,363,928	1,239,529	30.05
Kansas	3,796,262	3,797,394	1,132	0.03
Kentucky	12,152,376	11,706,885	(445,491)	−3.67
Louisiana	15,423,284	14,645,250	(778,034)	−5.04
Maine	2,056,296	2,027,635	(28,661)	−1.39
Maryland	15,785,149	14,981,809	(803,340)	−5.09
Massachusetts	20,790,363	19,860,355	(930,008)	−4.47
Michigan	28,698,440	27,746,873	(951,567)	−3.32
Minnesota	8,644,757	8,545,279	(99,478)	−1.15
Mississippi	12,778,348	11,917,714	(860,634)	−6.74
Missouri	10,047,765	9,804,128	(243,637)	−2.42
Montana	1,464,503	1,435,624	(28,879)	−1.97
Nebraska	1,840,202	1,827,388	(12,814)	−0.70
Nevada	19,863,366	25,833,014	5,969,648	30.05
New Hampshire	1,943,190	1,911,623	(31,567)	−1.62
New Jersey	33,449,845	32,469,628	(980,217)	−2.93
New Mexico	19,466,660	17,841,270	(1,625,390)	−8.35
New York	108,043,045	101,745,387	(6,297,658)	−5.83
North Carolina	21,512,837	21,045,970	(466,867)	−2.17
North Dakota	745,664	740,881	(4,783)	−0.64
Ohio	28,150,420	27,235,792	(914,628)	−3.25
Oklahoma	5,630,710	5,580,181	(50,529)	−0.90
Oregon	9,577,767	9,412,925	(164,842)	−1.72
Pennsylvania	55,648,335	52,261,354	(3,386,981)	−6.09
Puerto Rico	83,334,615	108,379,632	25,045,017	30.05
Rhode Island	3,257,943	3,120,263	(137,680)	−4.23
South Carolina	10,803,123	10,522,345	(280,778)	−2.60
South Dakota	1,212,439	1,159,463	(52,976)	−4.37
Tennessee	13,232,879	12,944,745	(288,134)	−2.18
Texas	76,447,629	74,893,848	(1,553,781)	−2.03
Utah	3,226,544	4,196,235	969,691	30.05
Vermont	922,108	896,318	(25,790)	−2.80
Virginia	12,979,165	12,811,909	(167,256)	−1.29
Washington	20,409,533	19,751,767	(657,766)	−3.22
West Virginia	9,730,541	9,022,367	(708,174)	−7.28
Wisconsin	9,973,277	9,838,615	(134,662)	−1.35

TABLE C—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WIOA DISLOCATED WORKER ACTIVITIES STATE ALLOTMENTS COMPARISON OF PY 2024 ALLOTMENTS VS PY 2023 ALLOTMENTS—Continued

State	PY 2023	PY 2024	Difference	% Difference
Wyoming	922,221	910,116	(12,105)	−1.31
State Total	1,092,263,000	1,092,713,000	450,000	0.04
American Samoa	491,627	502,290	10,663	2.17
Guam	1,349,203	1,378,467	29,264	2.17
Northern Marianas	631,612	643,704	12,092	1.91
Palau	120,397	118,327	(2,070)	−1.72
Virgin Islands	950,554	841,142	(109,412)	−11.51
Outlying Areas Total	3,543,393	3,483,930	(59,463)	−1.68
National Reserve	321,550,607	297,375,070	(24,175,537)	−7.52

TABLE D—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION EMPLOYMENT SERVICE (WAGNER-PEYSER) PY 2024 VS PY 2023 ALLOTMENTS

State	PY 2023	PY 2024	Difference	% Difference
Total	$677,531,500	$672,893,000	($4,638,500)	−0.68
Alabama	8,157,290	7,994,781	(162,509)	−1.99
Alaska	7,365,091	7,314,668	(50,423)	−0.68
Arizona	14,367,195	14,239,498	(127,697)	−0.89
Arkansas	5,068,542	4,999,917	(68,625)	−1.35
California	81,499,358	80,695,511	(803,847)	−0.99
Colorado	12,513,087	12,238,027	(275,060)	−2.20
Connecticut	7,546,077	7,419,418	(126,659)	−1.68
Delaware	2,041,275	2,017,779	(23,496)	−1.15
District of Columbia	1,924,337	1,904,601	(19,736)	−1.03
Florida	38,791,016	38,458,248	(332,768)	−0.86
Georgia	18,884,035	19,214,067	330,032	1.75
Hawaii	2,811,112	2,718,323	(92,789)	−3.30
Idaho	6,136,431	6,094,420	(42,011)	−0.68
Illinois	26,805,431	26,439,971	(365,460)	−1.36
Indiana	12,198,042	12,472,800	274,758	2.25
Iowa	6,083,922	6,042,244	(41,678)	−0.69
Kansas	5,370,575	5,313,527	(57,048)	−1.06
Kentucky	8,028,686	7,958,398	(70,288)	−0.88
Louisiana	8,511,466	8,313,405	(198,061)	−2.33
Maine	3,649,278	3,624,294	(24,984)	−0.68
Maryland	12,638,485	12,221,314	(417,171)	−3.30
Massachusetts	14,841,028	14,419,020	(422,008)	−2.84
Michigan	19,625,843	19,411,416	(214,427)	−1.09
Minnesota	10,868,056	10,827,663	(40,393)	−0.37
Mississippi	5,186,386	5,015,194	(171,192)	−3.30
Missouri	11,219,804	11,080,052	(139,752)	−1.25
Montana	5,014,722	4,980,390	(34,332)	−0.68
Nebraska	4,489,626	4,341,432	(148,194)	−3.30
Nevada	6,814,792	6,913,847	99,055	1.45
New Hampshire	2,625,284	2,576,103	(49,181)	−1.87
New Jersey	18,623,063	19,083,930	460,867	2.47
New Mexico	5,627,402	5,588,876	(38,526)	−0.68
New York	39,960,265	39,348,644	(611,621)	−1.53
North Carolina	19,548,712	19,364,936	(183,776)	−0.94
North Dakota	5,106,489	5,071,529	(34,960)	−0.68
Ohio	22,892,147	22,471,826	(420,321)	−1.84
Oklahoma	6,825,929	6,879,212	53,283	0.78
Oregon	8,641,616	8,477,061	(164,555)	−1.90
Pennsylvania	25,998,063	25,495,368	(502,695)	−1.93
Puerto Rico	5,882,119	5,746,432	(135,687)	−2.31
Rhode Island	2,217,710	2,163,331	(54,379)	−2.45
South Carolina	8,820,458	8,736,992	(83,466)	−0.95
South Dakota	4,719,570	4,687,259	(32,311)	−0.68
Tennessee	12,583,460	12,450,216	(133,244)	−1.06
Texas	57,724,443	58,414,716	690,273	1.20
Utah	5,704,059	6,074,652	370,593	6.50
Vermont	2,210,914	2,195,778	(15,136)	−0.68
Virginia	15,516,383	15,880,320	363,937	2.35
Washington	15,860,228	15,729,530	(130,698)	−0.82
West Virginia	5,402,014	5,365,031	(36,983)	−0.68

TABLE D—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION EMPLOYMENT SERVICE (WAGNER-PEYSER) PY 2024 VS PY 2023 ALLOTMENTS—Continued

State	PY 2023	PY 2024	Difference	% Difference
Wisconsin	11,276,927	11,130,151	(146,776)	−1.30
Wyoming	3,661,671	3,636,603	(25,068)	−0.68
State Total	675,879,914	671,252,721	(4,627,193)	−0.68
Guam	317,033	314,863	(2,170)	−0.68
Virgin Islands	1,334,553	1,325,416	(9,137)	−0.68
Outlying Areas Total	1,651,586	1,640,279	(11,307)	−0.68

TABLE E—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WORKFORCE INFORMATION GRANTS TO STATES PY 2024 VS PY 2023 ALLOTMENTS

State	PY 2023	PY 2024	Difference	% Difference
Total	$31,964,000	$31,969,000	$5,000	0.02
Alabama	507,924	505,972	(1,952)	−0.38
Alaska	286,168	285,206	(962)	−0.34
Arizona	657,611	663,102	5,491	0.83
Arkansas	400,348	401,719	1,371	0.34
California	2,464,249	2,447,256	(16,993)	−0.69
Colorado	616,964	612,458	(4,506)	−0.73
Connecticut	462,764	460,821	(1,943)	−0.42
Delaware	302,193	301,620	(573)	−0.19
District of Columbia	288,891	289,145	254	0.09
Florida	1,469,215	1,497,933	28,718	1.95
Georgia	852,260	846,780	(5,480)	−0.64
Hawaii	322,411	321,585	(826)	−0.26
Idaho	353,672	354,148	476	0.13
Illinois	987,543	978,103	(9,440)	−0.96
Indiana	632,989	633,577	588	0.09
Iowa	440,864	441,356	492	0.11
Kansas	417,786	417,115	(671)	−0.16
Kentucky	482,524	477,048	(5,476)	−1.13
Louisiana	485,663	483,015	(2,648)	−0.55
Maine	322,796	321,770	(1,026)	−0.32
Maryland	614,643	607,197	(7,446)	−1.21
Massachusetts	678,587	668,815	(9,772)	−1.44
Michigan	803,595	803,694	99	0.01
Minnesota	599,354	596,945	(2,409)	−0.40
Mississippi	390,181	385,572	(4,609)	−1.18
Missouri	599,314	597,989	(1,325)	−0.22
Montana	309,540	309,939	399	0.13
Nebraska	367,117	365,140	(1,977)	−0.54
Nevada	420,134	424,833	4,699	1.12
New Hampshire	332,764	331,313	(1,451)	−0.44
New Jersey	782,350	794,891	12,541	1.60
New Mexico	353,848	353,383	(465)	−0.13
New York	1,336,973	1,347,631	10,658	0.80
North Carolina	831,353	837,975	6,622	0.80
North Dakota	291,755	291,951	196	0.07
Ohio	911,075	902,447	(8,628)	−0.95
Oklahoma	460,596	463,247	2,651	0.58
Oregon	497,674	490,102	(7,572)	−1.52
Pennsylvania	986,238	983,560	(2,678)	−0.27
Puerto Rico	383,058	380,195	(2,863)	−0.75
Rhode Island	310,763	309,308	(1,455)	−0.47
South Carolina	520,463	520,302	(161)	−0.03
South Dakota	299,427	299,192	(235)	−0.08
Tennessee	634,898	626,684	(8,214)	−1.29
Texas	1,918,307	1,949,888	31,581	1.65
Utah	443,356	448,299	4,943	1.11
Vermont	283,068	283,941	873	0.31
Virginia	744,227	762,725	18,498	2.49
Washington	707,273	705,375	(1,898)	−0.27
West Virginia	336,359	333,882	(2,477)	−0.74
Wisconsin	606,138	597,751	(8,387)	−1.38
Wyoming	278,023	278,379	356	0.13

TABLE E—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WORKFORCE INFORMATION GRANTS TO STATES PY 2024 VS PY 2023 ALLOTMENTS—Continued

State	PY 2023	PY 2024	Difference	% Difference
State Total	31,787,286	31,792,274	4,988	0.02
Guam	97,657	97,665	8	0.01
Virgin Islands	79,057	79,061	4	0.01
Outlying Areas Total	176,714	176,726	12	0.01

TABLE F—U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WIOA YOUTH, ADULT, AND DISLOCATED WORKER OUTLYING AREAS FUNDING PY 2024

	Youth	Adult	Dislocated worker	Total
American Samoa	335,753	318,370	502,290	1,156,413
Guam	921,426	873,724	1,378,467	3,173,617
Northern Marianas	430,280	408,004	643,704	1,481,988
Palau	75,000	75,000	118,327	268,327
Virgin Islands	562,323	533,147	841,142	1,936,612
Outlying Areas Total	2,324,782	2,208,245	3,483,930	8,016,957

José Javier Rodríguez,

Assistant Secretary for Employment and Training, Labor.

[FR Doc. 2024–10074 Filed 5–8–24; 8:45 am]

BILLING CODE P

DEPARTMENT OF LABOR

Agency Information Collection Activities; Submission for OMB Review; Comment Request; Requirements of a Bona Fide Thrift or Savings Plan and Requirements of a Bona Fide Profit-Sharing Plan or Trust

ACTION: Notice of availability; request for comments.

SUMMARY: The Department of Labor (DOL) is submitting this Wage and Hour Division (WHD)-sponsored information collection request (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (PRA). Public comments on the ICR are invited.

DATES: The OMB will consider all written comments that the agency receives on or before June 10, 2024.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain*. Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

FOR FURTHER INFORMATION CONTACT: Michelle Neary by telephone at 202–693–6312, or by email at *DOL_PRA_PUBLIC@dol.gov*.

SUPPLEMENTARY INFORMATION: This information collection applies to employers claiming the overtime exemption available under section 7(e)(3)(b) of the Fair Labor Standards Act. Specifically, in calculating an employee's regular rate of pay, an employer need not include contributions made to a bona fide thrift or savings plan or a bona fide profit-sharing plan or trust—as defined in 29 CFR parts 547 and 549. Employers are required to communicate, or make available to the employees, the terms of the bona fide thrift or savings plan and bona fide profit-sharing plan or trust, and retain certain records. For additional substantive information about this ICR, see the related notice published in the **Federal Register** on December 20, 2023 (88 FR 88126).

Comments are invited on: (1) whether the collection of information is necessary for the proper performance of the functions of the Department, including whether the information will have practical utility; (2) if the information will be processed and used in a timely manner; (3) the accuracy of the agency's estimates of the burden and cost of the collection of information, including the validity of the methodology and assumptions used; (4) ways to enhance the quality, utility and clarity of the information collection; and (5) ways to minimize the burden of the collection of information on those who are to respond, including the use of automated collection techniques or other forms of information technology.

This information collection is subject to the PRA. A Federal agency generally cannot conduct or sponsor a collection of information, and the public is generally not required to respond to an information collection, unless the OMB approves it and displays a currently valid OMB Control Number. In addition, notwithstanding any other provisions of law, no person shall generally be subject to penalty for failing to comply with a collection of information that does not display a valid OMB Control Number. *See* 5 CFR 1320.5(a) and 1320.6.

DOL seeks PRA authorization for this information collection for three (3) years. OMB authorization for an ICR cannot be for more than three (3) years without renewal. The DOL notes that information collection requirements submitted to the OMB for existing ICRs receive a month-to-month extension while they undergo review.

Agency: DOL–WHD.

Title of Collection: Requirements of a Bona Fide Thrift or Savings Plan and Requirements of a Bona Fide Profit-Sharing Plan or Trust.

OMB Control Number: 1235–0013.

Affected Public: Private Sector—Businesses or other for-profits; Farms; Not-for-profit institutions.

Total Estimated Number of Respondents: 3,254,524.

Total Estimated Number of Responses: 4,393,607.

Total Estimated Annual Time Burden: 2,441 hours.

Total Estimated Annual Other Costs Burden: $0.

(Authority: 44 U.S.C. 3507(a)(1)(D))

Michelle Neary,

Senior Paperwork Reduction Act Analyst.

[FR Doc. 2024–10070 Filed 5–8–24; 8:45 am]

BILLING CODE 4510–27–P

DEPARTMENT OF LABOR

Agency Information Collection Activities; Submission for OMB Review; Comment Request; Excavations (Design of Cave-In Protection Systems)

ACTION: Notice of availability; request for comments.

SUMMARY: The Department of Labor (DOL) is submitting this Occupational Safety & Health Administration (OSHA)-sponsored information collection request (ICR) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995 (PRA). Public comments on the ICR are invited.

DATES: The OMB will consider all written comments that the agency receives on or before June 10, 2024.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

FOR FURTHER INFORMATION CONTACT: Nicole Bouchet by telephone at 202–693–0213, or by email at *DOL_PRA_PUBLIC@dol.gov.*

SUPPLEMENTARY INFORMATION: Design of cave-in protection systems are needed by employers in the construction industry and OSHA compliance officers to ensure that cave-in protection systems are designed, installed, and used in a manner to protect workers adequately. For additional substantive information about this ICR, see the related notice published in the **Federal Register** on February 23, 2024 (89 FR 13750).

Comments are invited on: (1) whether the collection of information is necessary for the proper performance of the functions of the Department, including whether the information will have practical utility; (2) the accuracy of the agency's estimates of the burden and cost of the collection of information, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility and clarity of the information collection; and (4) ways to minimize the burden of the collection of information on those who are to respond, including the use of automated collection techniques or other forms of information technology.

This information collection is subject to the PRA. A Federal agency generally cannot conduct or sponsor a collection of information, and the public is generally not required to respond to an information collection, unless the OMB approves it and displays a currently valid OMB Control Number. In addition, notwithstanding any other provisions of law, no person shall generally be subject to penalty for failing to comply with a collection of information that does not display a valid OMB Control Number. *See* 5 CFR 1320.5(a) and 1320.6.

DOL seeks PRA authorization for this information collection for three (3) years. OMB authorization for an ICR cannot be for more than three (3) years without renewal. The DOL notes that information collection requirements submitted to the OMB for existing ICRs receive a month-to-month extension while they undergo review.

Agency: DOL–OSHA.

Title of Collection: Excavations (Design of Cave-in Protection Systems).

OMB Control Number: 1218–0137.

Affected Public: Private Sector—Businesses or other for-profits.

Total Estimated Number of Respondents: 1,144,081.

Total Estimated Number of Responses: 22,697.

Total Estimated Annual Time Burden: 22,697 hours.

Total Estimated Annual Other Costs Burden: $430,152.

(Authority: 44 U.S.C. 3507(a)(1)(D))

Nicole Bouchet,

Certifying Official.

[FR Doc. 2024–10068 Filed 5–8–24; 8:45 am]

BILLING CODE 4510–26–P

NATIONAL CREDIT UNION ADMINISTRATION

Renewal of Agency Information Collection of a Previously Approved Collection; Request for Comments

AGENCY: National Credit Union Administration (NCUA).

ACTION: Notice of submission to the Office of Management and Budget.

SUMMARY: As required by the Paperwork Reduction Act of 1995, The National Credit Union Administration (NCUA) is submitting the following extensions and revisions of currently approved collections to the Office of Management and Budget (OMB) for renewal.

DATES: Written comments should be received on or before June 10, 2024 to be assured consideration.

ADDRESSES: Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function.

FOR FURTHER INFORMATION CONTACT: Copies of the submission may be obtained by contacting Dacia Rogers at (703) 718–1155, emailing *PRAComments@ncua.gov,* or viewing the entire information collection request at *www.reginfo.gov.*

SUPPLEMENTARY INFORMATION:

OMB Number: 3133–0165.

Title: Fair Credit Reporting (FCRA); Regulation V and 12 CFR 717.

Type of Review: Revision of a currently approved collection.

Abstract: As required under the Fair Credit Reporting Act, federal credit unions must give consumers an opportunity to opt out from the credit union's sharing of information covered by FCRA, which is other than transaction and experience information, before communicating such information to its affiliates.

Affected Public: Private Sector: Not-for-profit institutions.

Estimated Number of Respondents: 2,869.

Estimated Number of Responses per Respondent: 112.0467

Estimated Total Annual Responses: 321,462.

Estimated Hours per Response: 0.767835.

Estimated Total Annual Burden Hours: 246,830.

Reason for Change: The number of respondents decreased and the estimated annual burden hours decreased.

Request for Comments: Comments submitted in response to this notice will be summarized and included in the request for Office of Management and Budget approval. All comments will become a matter of public record. The public is invited to submit comments concerning: (a) whether the collection of information is necessary for the proper performance of the function of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of the burden of the collection of information, including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility,

and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of the information on the respondents, including the use of automated collection techniques or other forms of information technology.

By the National Credit Union Administration Board.

Melane Conyers-Ausbrooks,

Secretary of the Board.

[FR Doc. 2024–10122 Filed 5–8–24; 8:45 am]

BILLING CODE 7535–01–P

NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

Institute of Museum and Library Services

Submission for OMB Review, Comment Request, Proposed Collection: 2025–2027 IMLS National Leadership Grants for Libraries and Laura Bush 21st Century Librarian Program Notices of Funding Opportunity

AGENCY: Institute of Museum and Library Services, National Foundation on the Arts and the Humanities.

ACTION: Submission for OMB review, comment request, collection of information.

SUMMARY: The Institute of Museum and Library Services (IMLS) announces the following information collection has been submitted to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act. This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed. The purpose of this Notice is to solicit comments concerning two grant programs targeting the needs of libraries and their communities nationwide: IMLS National Leadership Grants for Libraries and the IMLS Laura Bush 21st Century Librarian Program.

DATES: Written comments must be submitted to the office listed in the **ADDRESSES** section below on or before June 08, 2024.

ADDRESSES: Written comments and recommendations for proposed information collection requests should be sent within 30 days of publication of this Notice to *www.reginfo.gov/public/do/PRAMain*. Find this particular information collection request by selecting ''Institute of Museum and Library Services'' under ''Currently Under Review;'' then check ''Only Show ICR for Public Comment'' checkbox. Once you have found this information collection request, select ''Comment,'' and enter or upload your comment and information. Alternatively, please mail your written comments to Office of Information and Regulatory Affairs, Attn.: OMB Desk Officer for Education, Office of Management and Budget, Room 10235, Washington, DC 20503, or call (202) 395–7316.

FOR FURTHER INFORMATION CONTACT: Anthony D. Smith, Acting Deputy Director, Office of Library Services, Institute of Museum and Library Services, 955 L'Enfant Plaza North SW, Suite 4000, Washington, DC 20024–2135. Mr. Smith can be reached by telephone at 202–653–4716, or by email at *asmith@imls.gov*. Office hours are from 8:30 a.m. to 5 p.m., E.T., Monday through Friday, except Federal holidays. Persons who are deaf or hard of hearing (TTY users) can contact IMLS at 202–207–7858 via 711 for TTY-Based Telecommunications Relay Service.

SUPPLEMENTARY INFORMATION: IMLS is the primary source of federal support for the nation's libraries and museums. We advance, support, and empower America's museums, libraries, and related organizations through grant making, research, and policy development. To learn more, visit *www.imls.gov.*

Current Actions: The IMLS National Leadership Grants for Libraries Program supports projects that enhance the quality of library and archive services nationwide by advancing theory and practice and by generating results such as new tools, research findings, models, services, practices, or collaborative approaches that can be widely used, adapted, scaled, or replicated to extend the benefits of federal investment.

The IMLS Laura Bush 21st Century Librarian Program supports developing a diverse workforce of librarians to better meet the changing learning and information needs of the American public by enhancing the training and professional development of library and archives professionals; developing faculty and library leaders; and recruiting, educating, and retaining the next generation of library and archives professionals.

This action is to renew the content, forms, and instructions for the two Notices of Funding Opportunity for the next three years (FY25–FY27).

OMB is particularly interested in comments that help the agency to:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.,* permitting electronic submission of responses).

The 60-Day Notice was published in the **Federal Register** on February 27, 2024 (89 FR 14525) (Document Number 2024–03983). We received and replied to one comment in response to this Notice. A copy of the proposed information collection request can be obtained by contacting the individual listed in the **FOR FURTHER INFORMATION CONTACT** section of this notice.

Agency: Institute of Museum and Library Services.

Title: 2025–2027 IMLS National Leadership Grants for Libraries and Laura Bush 21st Century Librarian Program Notices of Funding Opportunity.

OMB Control Number: 3137–0091.

Agency Number: 3137.

Affected Public: Library applicants.

Total Number of Respondents: 400.

Frequency of Response: Once per request.

Average Hours Per Response: 45.

Total Estimated Number of Burden Hours: 18,000.

Total Annual Cost Burden: $560,520.

Total Annual Federal Costs: $90,783.

Dated: May 3, 2024.

Suzanne Mbollo,

Grants Management Specialist, Institute of Museum and Library Services.

[FR Doc. 2024–10094 Filed 5–8–24; 8:45 am]

BILLING CODE 7036–01–P

NATIONAL SCIENCE FOUNDATION

Committee on Equal Opportunities in Science and Engineering; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science

Foundation (NSF) announces the following meeting:

Name and Committee Code: Committee on Equal Opportunities in Science and Engineering (CEOSE) (#1173) (Virtual)

Date and Time:

June 13, 2024; 1:00 p.m.–5:30 p.m.

June 14, 2024; 10:00 a.m.–4:00 p.m.

Place: National Science Foundation, 2415 Eisenhower Avenue, Alexandria, VA 22314 (Virtual).

Meeting Registration: Virtual attendance information will be forthcoming on the CEOSE website at: *http://www.nsf.gov/od/oia/activities/ceose/index.jsp.*

Type of Meeting: Open.

Contact Person: Dr. Bernice Anderson, Senior Advisor and CEOSE Executive Secretary, Office of Integrative Activities (OIA), National Science Foundation, 2415 Eisenhower Avenue, Alexandria, VA 22314. Contact Information: Phone: 703–292–8040, Email: *banderso@nsf.gov.*

Minutes: Meeting minutes and other information may be obtained from the CEOSE Executive Secretary at the above address or from the CEOSE website at: *http://www.nsf.gov/od/oia/activities/ceose/index.jsp.*

Purpose of Meeting: To study data, programs, policies, and other information pertinent to the National Science Foundation and to provide advice and recommendations concerning broadening participation in science and engineering.

Agenda: CEOSE Agenda-at-a-Glance.

Day 1: June 13, 2024

1:00 p.m.–1:30 p.m. Opening, Welcome, Introduction
1:30 p.m.–2:00 p.m. Presentation: Report of the CEOSE Executive Liaison
2:30 p.m.–3:00 p.m. NSF Supporting Native Communities: Part II
3:00 p.m.–3:15 p.m. *Break*
3:15 p.m.–4:30 p.m. Presentation: NSB/NSF Commission on Merit Review
4:30 p.m.–5:30 p.m. Discussion: Reports of the CEOSE AC Liaisons

Day 2: June 14, 2024

10:00 a.m.–10:15 a.m. Opening Remarks
10:15 a.m.–11:15 a.m. Work Session for Writing Te a.m.s of the 2023–2024 CEOSE Report
11:15 a.m.–12:00 p.m. Briefing: NSF EBJ INCLUDES Initiative
12:00 p.m.–1:30 p.m. Working Lunch: Topics/Advice to Share with NSF Senior Leadership
1:30 p.m.–2:00 p.m. Discussion with NSF Leadership
2:00 p.m.–2:15 p.m. *Break*
2:15 p.m.–3:30 p.m. Panel: STEM Accessibility
3:30 p.m.–3:45 p.m. Discussion: 2023–2024 CEOSE Report to Congress
3:45 p.m.–4:00 p.m. Announcements, Closing Remarks, Adjournment

Dated: May 3, 2024.

Crystal Robinson,

Committee Management Officer.

[FR Doc. 2024–10116 Filed 5–8–24; 8:45 am]

BILLING CODE 7555–01–P

NATIONAL SCIENCE FOUNDATION

Astronomy and Astrophysics Advisory Committee; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation (NSF) announces the following meeting:

Name and Committee Code: Astronomy and Astrophysics Advisory Committee (#13883) (Virtual).

Date and Time: June 6, 2024; 9:30 a.m.–4:00 p.m.; June 7, 2024, 9:30 a.m.–4:00 p.m.

Place: National Science Foundation, 2415 Eisenhower Avenue, Room W2190, Alexandria, VA 22314/Virtual.

Attendance information for the meeting will be forthcoming on the advisory committee website at: *https://www.nsf.gov/mps/ast/aaac.jsp.*

Type of Meeting: Open.

Contact Person: Dr. Daniel Fabrycky, Program Director, Division of Astronomical Sciences, Suite W 9176, National Science Foundation, 2415 Eisenhower Avenue, Alexandria, VA 22314; Telephone: 703–292–8490.

Purpose of Meeting: To provide advice and recommendations to the National Science Foundation (NSF), the National Aeronautics and Space Administration (NASA) and the U.S. Department of Energy (DOE) on issues within the field of astronomy and astrophysics that are of mutual interest and concern to the agencies. To prepare the annual report.

Agenda: To hear presentations of current programming by representatives from NSF, NASA, DOE and other agencies relevant to astronomy and astrophysics; to discuss current and potential areas of cooperation between the agencies; to formulate recommendations for continued and new areas of cooperation and mechanisms for achieving them.

Dated: May 3, 2024.

Crystal Robinson,

Committee Management Officer.

[FR Doc. 2024–10121 Filed 5–8–24; 8:45 am]

BILLING CODE 7555–01–P

NATIONAL SCIENCE FOUNDATION

Advisory Committee for Social, Behavioral & Economic Sciences; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation (NSF) announces the following meeting:

Name and Committee Code: Advisory Committee for Social, Behavioral & Economic Sciences (SBE) (#1171) (Hybrid).

Date and Time: June 6–7, 2024, 10:00 a.m.–4:00 p.m. (Eastern).

Place:

NSF, 2415 Eisenhower Avenue, Room W 2230, Alexandria, VA 22314 (In-Person and Virtual).

The meeting will be held in a hybrid format, with some Advisory Committee members participating in person and others participating virtually. For members of NSF and the external community, livestreaming and registration links will be available through the following page: *https://new.nsf.gov/sbe/advisory-committee.*

Type of Meeting: Open.

Contact Persons: Kurt DeSoto, National Science Foundation, 2415 Eisenhower Avenue, Alexandria, VA 22314; Telephone: 703–292–8700.

Purpose of Meeting: To provide advice, recommendations and counsel on major goals and policies pertaining to SBE programs and activities.

Agenda:

- Welcome, Introductions, Approval of Previous Advisory Committee (AC) Meeting Summary, and Preview of Agenda
- Directorate for Social, Behavioral, and Economic Sciences (SBE) Update
- Discussion on the National Secure Data Service Demonstration and the National Artificial Intelligence Research Resource Pilot
- SBE Contributions to Building a Resilient Planet and Committee Discussion
- SBE Contributions to Creating Opportunities Everywhere and Committee Discussion
- New AC Member Presentation
- Advisory Committee on Environmental Research and Education Update
- Meeting with NSF Leadership
- Wrap-up, Assignments, Closing Remarks

Dated: May 6, 2024.

Crystal Robinson,

Committee Management Officer.

[FR Doc. 2024–10129 Filed 5–8–24; 8:45 am]

BILLING CODE 7555–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 70–7033; NRC–2024–0061]

Global Laser Enrichment, LLC.; New Headquarters; Environmental Assessment and Finding of No Significant Impact

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice; issuance.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) staff is considering approval of a revision to the program cyber security plan (PCSP) held by Global Laser Enrichment, LLC (GLE) to extend the classified network to a new headquarters building. The NRC staff is issuing an environmental assessment (EA) and finding of no significant impact (FONSI) associated with the proposed revisions.

DATES: The EA and FONSI referenced in this document are available on May 9, 2024.

ADDRESSES: Please refer to Docket ID NRC–2024–0061 when contacting the NRC about the availability of information regarding this document. You may obtain publicly available information related to this document using any of the following methods:

- *Federal Rulemaking website:* Go to *https://www.regulations.gov* and search for Docket ID NRC–2024–0061. Address questions about Docket IDs in *Regulations.gov* to Stacy Schumann; telephone: 301–415–0624; email: *Stacy.Schumann@nrc.gov.* For technical questions, contact the individual listed in the ''For Further Information Contact'' section of this document.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly available documents online in the ADAMS Public Documents collection at *https://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''Begin Web-based ADAMS Search.'' For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, at 301–415–4737, or by email to *PDR.Resource@nrc.gov.* For the convenience of the reader, instructions about obtaining materials referenced in this document are provided in the ''Availability of Documents'' section. Individuals seeking access to Official Use Only information should contact Matthew Bartlett, using the contact information below.
- *NRC's PDR:* The PDR, where you may examine and order copies of publicly available documents, is open by appointment. To make an appointment to visit the PDR, please send an email to *PDR.Resource@nrc.gov* or call 1–800–397–4209 or 301–415–4737, between 8 a.m. and 4 p.m. eastern time (ET), Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Matthew Bartlett, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, telephone: 301–415–7154; email: *Matthew.Bartlett@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Introduction

The NRC staff is considering the approval of an update to a PCSP held by GLE for operations at a new headquarters, located in Wilmington, NC, approximately 6.2 miles from GLE's existing test loop facility. Therefore, as required by section 51.21 of title 10 of the *Code of Federal Regulations* (10 CFR), ''Criteria for and identification of licensing and regulatory actions requiring environmental assessments,'' the NRC staff has prepared an EA that analyzes the environmental effects of the proposed action. Based on the results of the EA and in accordance with 10 CFR 51.31(a), the NRC staff is issuing a FONSI for the proposed update to the PCSP.

Approval of the updated PCSP would allow for the incorporation of classified systems at the new headquarters building into the existing GLE authorization to operate a classified network. The request for approval of an updated PCSP was submitted September 21, 2023, and updated November 13, 2023. The NRC staff is also considering the approval of a separate but related request for issuance of a facility clearance under 10 CFR part 95 for GLE's new headquarters building, published in the **Federal Register** on April 29, 2024 (89 FR 33404).

II. Environmental Assessment

Description of the Proposed Action

The proposed action would allow GLE to extend the classified computer network to a new headquarters location approximately 6.2 miles from the test loop. As proposed, GLE would continue to possess, use, and store classified matter at its test loop facility and would also possess, use, and store classified matter at the new headquarters location under the revised PCSP. GLE operates a test loop for industrialization of the uranium enrichment process that uses separation of isotopes by laser excitation. Although GLE has an NRC-issued facility security clearance for the test loop facility under 10 CFR part 95 for protection of classified matter, the facility's operations, safety, and safeguards programs are authorized under the Global Nuclear Fuel—America license SNM–1097.

Need for the Proposed Action

The proposed action would allow GLE to extend the classified computer network to a new headquarters location to facilitate further research and development potentially leading to the industrialization of the laser enrichment process. The proposed NRC staff approval of the updated PCSP would add approval for the possession and use of classified matter at the new headquarters location.

Environmental Impacts of the Proposed Action

The NRC staff has assessed the potential environmental impacts from GLE's updated PCSP. The classified systems at the headquarters building will include appropriate controls for the protection of classified matter. These headquarter systems will facilitate the exchange of classified matter with the test loop facility but will have no operational or environmental impacts on the test loop. The NRC staff evaluated the potential for impacts at the GLE headquarters facility from the proposed action, which involves only changes to information systems. The NRC staff concluded that the proposed action will cause no significant change in the types of or significant increase in the amounts of any effluents that may be released offsite, that there will be no significant increase in individual or cumulative occupational radiation exposure, that there will be no significant construction impact, and that there will be no significant increase in the potential for or consequences from radiological accidents. The NRC staff assessed the impacts of the proposed action on land use; historical and cultural resources; visual and scenic resources; climatology, meteorology and air quality; geology, minerals, and soils; water resources; ecological resources; socioeconomics; noise; traffic and transportation; public and occupational health and safety; and waste management and concluded that the proposed action would have no significant environmental impacts on these resource areas. The NRC staff

determined that there are no cumulative impacts associated with the proposed action.

Environmental Impacts of the Alternatives to the Proposed Action

As an alternative to the proposed action, the staff considered denial of the proposed action (*i.e.,* the ''no-action'' alternative). Under this alternative, GLE would not be granted approval of the updated cyber security plan. Denial of the proposed action would result in GLE being unable to conduct operations related to classified matter at its headquarters location. GLE would continue its current operations at the test loop facility. The NRC staff concluded that environmental impacts from the no-action alternative would not be significant.

Agencies and Persons Consulted

The Endangered Species Act (ESA) was enacted to prevent further decline of endangered and threatened species and restore those species and their critical habitat. Section 7 of the ESA requires Federal agencies to consult with the U.S. Fish and Wildlife Service or the National Marine Fisheries Service, as appropriate, regarding actions that may affect listed species or designated critical habitats. The NRC staff has determined that the proposed action would have no effect on threatened or endangered species or critical habitat. Therefore, consultation under section 7 of the ESA is not required.

Section 106 of the National Historic Preservation Act (NHPA) requires Federal agencies to consider the effects of their undertakings on historic properties. As stated in the NHPA, historic properties are any prehistoric or historic district, site, building, structure, or object included in or eligible for inclusion in the National Register of Historic Places. The NRC staff has determined that the undertaking is a type of activity that does not have the potential to cause effects on any historic properties that may be present. Therefore, in accordance with 36 CFR 800.3(a)(1), the NRC has no further obligations under section 106 of the NHPA.

III. Finding of No Significant Impact

GLE has requested approval of its updated PCSP. The NRC staff has prepared an EA as part of its review of the proposed action. The proposed action would have no significant radiological or non-radiological impacts to environmental resources. This FONSI incorporates by reference the EA in Section II of this notice. On the basis of this EA, the NRC staff concludes that the proposed action will not have a significant effect on the quality of the human environment. Accordingly, the NRC has determined not to prepare an environmental impact statement.

IV. Availability of Documents

The documents identified in the following table are available to interested persons through one or more of the following methods, as indicated.

Document description	ADAMS Accession No.
Approval of Updates to the Global Laser Enrichment LLC Standard Practice, Procedure Plan and Transportation Plan, to Support the New, Off-Site Headquarters Building, dated May 1, 2024.	ML24037A127
Submission of Global Laser Enrichment, LLC Cyber Security Plan Incorporating Coverage for the new GLE Headquarters, dated September 21, 2023.	ML23283A247
Submission of Global Laser Enrichment Program Cyber Security Plan Incorporating Coverage for the new GLE Headquarters updated PCSP, dated November 13, 2023.	ML23335A135

Dated: May 5, 2024.

For the Nuclear Regulatory Commission.

Samantha Lav,

Chief, Fuel Facilities Licensing Branch, Division of Fuel Management, Office of Nuclear Material Safety and Safeguards.

[FR Doc. 2024–10124 Filed 5–8–24; 8:45 am]

BILLING CODE 7590–01–P

PENSION BENEFIT GUARANTY CORPORATION

Proposed Submission of Information Collection for OMB Review; Comment Request; Mergers and Transfers Between Multiemployer Plans

AGENCY: Pension Benefit Guaranty Corporation.

ACTION: Notice of intent to request extension of OMB approval of information collection.

SUMMARY: The Pension Benefit Guaranty Corporation (PBGC) intends to request that the Office of Management and Budget (OMB) extend approval, under the Paperwork Reduction Act, of a collection of information contained in PBGC's regulation on Mergers and Transfers Between Multiemployer Plans. This notice informs the public of PBGC's intent and solicits public comment on the collection of information.

DATES: Comments must be submitted on or before July 8, 2024.

ADDRESSES: Comments may be submitted by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Email: paperwork.comments@pbgc.gov.* Refer to OMB control number 1212–0022 in the subject line.
- *Mail or Hand Delivery:* Regulatory Affairs Division, Office of the General Counsel, Pension Benefit Guaranty Corporation, 445 12th Street SW, Washington, DC 20024–2101.

Commenters are strongly encouraged to submit comments electronically. Commenters who submit comments on paper by mail should allow sufficient time for mailed comments to be received before the close of the comment period.

All submissions received must include the agency's name (Pension Benefit Guaranty Corporation, or PBGC) and refer to OMB control number 1212–0022. All comments received will be posted without change to PBGC's website, *www.pbgc.gov,* including any personal information provided. Do not submit comments that include any personally identifiable information or confidential business information.

Copies of the collection of information may be obtained without charge by writing to the Disclosure Division, (*disclosure@pbgc.gov*), Office of the General Counsel, Pension Benefit Guaranty Corporation, 445 12th Street SW, Washington, DC 20024–2101; or, calling 202–229–4040 during normal business hours. If you are deaf or hard of hearing, or have a speech disability, please dial 7–1–1 to access telecommunications relay services.

FOR FURTHER INFORMATION CONTACT: Monica O'Donnell (*odonnell.monica@pbgc.gov*), Attorney, Regulatory Affairs Division, Office of the General Counsel, Pension Benefit Guaranty Corporation, 445 12th Street SW, Washington DC 20024–2101; 202–229–8706. If you are

deaf or hard of hearing, or have a speech disability, please dial 7–1–1 to access telecommunications relay services.

SUPPLEMENTARY INFORMATION: Section 4231(a) and (b) of the Employee Retirement Income Security Act of 1974 (ERISA) requires plans that are involved in a merger or transfer to give PBGC 120 days notice of the transaction and provides that if PBGC determines that specified requirements are satisfied, the transaction will be deemed not to be in violation of ERISA section 406(a) or (b)(2) (dealing with prohibited transactions).

PBGC's regulation on Mergers and Transfers Between Multiemployer Plans (29 CFR part 4231) sets forth the procedures for giving notice of a merger or transfer under section 4231 and for requesting a compliance determination. The regulations specify the information that must be included in a merger or transfer notice. A request for a compliance determination must provide additional information to enable PBGC to make an explicit finding that the merger/transfer requirements have been satisfied.

Section 4231(e) of ERISA clarifies PBGC's authority to facilitate a merger (a ''facilitated merger'') of two or more multiemployer plans if certain statutory requirements are met. For purposes of section 4231(e), ''facilitation'' may include training, technical assistance, mediation, communication with stakeholders, and support with related requests to other government agencies. In addition, subject to the requirements of section 4231(e)(2), PBGC may provide financial assistance (within the meaning of section 4261 of ERISA) to facilitate a merger (a ''financial assistance merger'') it determines is necessary to enable one or more of the plans involved to avoid or postpone insolvency. PBGC's regulations specify the information requirements for a voluntary request for a facilitated merger under section 4231(e) of ERISA, including a financial assistance merger.

PBGC uses information submitted by plan sponsors under the regulation to determine whether mergers and transfers conform to the requirements of ERISA section 4231 and the regulation.

The collection of information under the regulation has been approved by OMB under control number 1212–0022 (expires October 31, 2024). PBGC intends to request that OMB extend approval of the collection for 3 years. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

PBGC estimates that there are 15 transactions each year (excluding financial assistance mergers). The estimated annual burden of the collection of information for 15 transactions (excluding financial assistance mergers) is 15 fund office hours and $74,400 in contractor costs for work by attorneys and actuaries. PBGC further estimates that there is one request each year for a financial assistance merger. The annual burden of the collection of information for financial assistance mergers is 10 fund office hours and $36,000 in contractor costs. The total annual burden of the collection of information is approximately 25 fund office hours and $110,400 in contractor costs.

PBGC is soliciting public comments to—

- Evaluate whether the proposed collection of information is necessary for the proper

performance of the functions of the agency, including whether the information will have practical utility;

- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodologies and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

Issued in Washington, DC.

Hilary Duke,

Assistant General Counsel for Regulatory Affairs, Pension Benefit Guaranty Corporation.

[FR Doc. 2024–10165 Filed 5–8–24; 8:45 am]

BILLING CODE 7709–02–P

POSTAL REGULATORY COMMISSION

[Docket Nos. MC2024–267 and CP2024–273; MC2024–268 and CP2024–274; MC2024–269 and CP2024–275; MC2024–270 and CP2024–276; MC2024–271 and CP2024–277]

New Postal Products

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: The Commission is noticing a recent Postal Service filing for the Commission's consideration concerning a negotiated service agreement. This notice informs the public of the filing, invites public comment, and takes other administrative steps.

DATES: *Comments are due:* May 13, 2024.

ADDRESSES: Submit comments electronically via the Commission's Filing Online system at *http://www.prc.gov.* Those who cannot submit comments electronically should contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section by telephone for advice on filing alternatives.

FOR FURTHER INFORMATION CONTACT: David A. Trissell, General Counsel, at 202–789–6820.

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Introduction
II. Docketed Proceeding(s)

I. Introduction

The Commission gives notice that the Postal Service filed request(s) for the Commission to consider matters related to negotiated service agreement(s). The request(s) may propose the addition or removal of a negotiated service agreement from the Market Dominant or the Competitive product list, or the modification of an existing product currently appearing on the Market Dominant or the Competitive product list.

Section II identifies the docket number(s) associated with each Postal Service request, the title of each Postal Service request, the request's acceptance date, and the authority cited by the Postal Service for each request. For each request, the Commission appoints an officer of the Commission to represent the interests of the general public in the proceeding, pursuant to 39 U.S.C. 505 (Public Representative). Section II also establishes comment deadline(s) pertaining to each request.

The public portions of the Postal Service's request(s) can be accessed via the Commission's website (*http://www.prc.gov*). Non-public portions of the Postal Service's request(s), if any, can be accessed through compliance with the requirements of 39 CFR 3011.301.[1]

The Commission invites comments on whether the Postal Service's request(s) in the captioned docket(s) are consistent with the policies of title 39. For request(s) that the Postal Service states concern Market Dominant product(s),

[1] *See* Docket No. RM2018–3, Order Adopting Final Rules Relating to Non-Public Information, June 27, 2018, Attachment A at 19–22 (Order No. 4679).

applicable statutory and regulatory requirements include 39 U.S.C. 3622, 39 U.S.C. 3642, 39 CFR part 3030, and 39 CFR part 3040, subpart B. For request(s) that the Postal Service states concern Competitive product(s), applicable statutory and regulatory requirements include 39 U.S.C. 3632, 39 U.S.C. 3633, 39 U.S.C. 3642, 39 CFR part 3035, and 39 CFR part 3040, subpart B. Comment deadline(s) for each request appear in section II.

II. Docketed Proceeding(s)

1. *Docket No(s).:* MC2024–267 and CP2024–273; *Filing Title:* USPS Request to Add Priority Mail & USPS Ground Advantage Contract 240 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* May 3, 2024; *Filing Authority:* 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative:* Jennaca D. Upperman; *Comments Due:* May 13, 2024.

2. *Docket No(s).:* MC2024–268 and CP2024–274; *Filing Title:* USPS Request to Add Priority Mail & USPS Ground Advantage Contract 241 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* May 3, 2024; *Filing Authority:* 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative:* Jennaca D. Upperman; *Comments Due:* May 13, 2024.

3. *Docket No(s).:* MC2024–269 and CP2024–275; *Filing Title:* USPS Request to Add Priority Mail & USPS Ground Advantage Contract 242 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* May 3, 2024; *Filing Authority:* 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative:* Jana Slovinska; *Comments Due:* May 13, 2024.

4. *Docket No(s).:* MC2024–270 and CP2024–276; *Filing Title:* USPS Request to Add Priority Mail & USPS Ground Advantage Contract 243 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* May 3, 2024; *Filing Authority:* 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative:* Jana Slovinska; *Comments Due:* May 13, 2024.

5. *Docket No(s).:* MC2024–271 and CP2024–277; *Filing Title:* USPS Request to Add Priority Mail & USPS Ground Advantage Contract 244 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* May 3, 2024; *Filing Authority:* 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative:* Almaroof Agoro; *Comments Due:* May 13, 2024.

This Notice will be published in the **Federal Register**.

Erica A. Barker,

Secretary.

[FR Doc. 2024–10176 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 3, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 243 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–270, CP2024–276.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10101 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on April 30, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 236 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–263, CP2024–269.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10111 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on April 29, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 231 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–257, CP2024–263.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10106 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail Express, Priority Mail, USPS Ground Advantage®, and Parcel Select Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean C. Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on April 29, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail Express, Priority Mail, USPS Ground Advantage®, and Parcel Select Contract 5 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–256, CP2024–262.

Sean C. Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10105 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on April 29, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 233 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–259, CP2024–265.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10108 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on April 29, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 234 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–260, CP2024–266.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10109 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 3, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 244 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–271, CP2024–277.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10102 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 3, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 240 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–267, CP2024–273.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10115 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on April 29, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 232 to Competitive Product List.* Documents

are available at *www.prc.gov,* Docket Nos. MC2024–258, CP2024–264.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10107 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 1, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 238 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–265, CP2024–271.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10113 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 1, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 239 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–266, CP2024–272.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10114 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 3, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 242 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–269, CP2024–275.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10100 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 1, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 237 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–264, CP2024–270.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10112 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on April 30, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 235 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–262, CP2024–268.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10110 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail Express Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal

Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on April 30, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail Express Contract 101 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–261, CP2024–267.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10104 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 3, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 245 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–272, CP2024–278.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10103 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

POSTAL SERVICE

Product Change—Priority Mail and USPS Ground Advantage® Negotiated Service Agreement

AGENCY: Postal Service™.

ACTION: Notice.

SUMMARY: The Postal Service gives notice of filing a request with the Postal Regulatory Commission to add a domestic shipping services contract to the list of Negotiated Service Agreements in the Mail Classification Schedule's Competitive Products List.

DATES: *Date of required notice:* May 9, 2024.

FOR FURTHER INFORMATION CONTACT: Sean Robinson, 202–268–8405.

SUPPLEMENTARY INFORMATION: The United States Postal Service® hereby gives notice that, pursuant to 39 U.S.C. 3642 and 3632(b)(3), on May 3, 2024, it filed with the Postal Regulatory Commission a *USPS Request to Add Priority Mail & USPS Ground Advantage® Contract 241 to Competitive Product List.* Documents are available at *www.prc.gov,* Docket Nos. MC2024–268, CP2024–274.

Sean Robinson,

Attorney, Corporate and Postal Business Law.

[FR Doc. 2024–10099 Filed 5–8–24; 8:45 am]

BILLING CODE 7710–12–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–100060; File No. SR–Phlx–2024–18]

Self-Regulatory Organizations; Nasdaq PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend Its Fee Schedule at Equity 7, Section 3 To Implement a Market Data Revenue Rebate Program

May 3, 2024.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on April 25, 2024, Nasdaq PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend its fee schedule at Equity 7, Section 3 to implement a Market Data Revenue Rebate program, as described further below.

The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/phlx/rules,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend its fee schedule at Equity 7, Section 3 to adopt a Market Data Revenue (''MDR'') Rebate program for Nasdaq PSX.[3] In sum, the proposed MDR Rebate program calls for 40% of MDR that exceeds fixed thresholds in any one of two pools (''Excess MDR'') to be shared with PSX Participants in proportion to their respective eligible quoting activity in Tape A and C securities, as described further below. The proposed MDR Rebate program is designed to improve displayed liquidity and promote order flow to the Exchange by offering an incentive for market participants to quote on the Exchange.

Background

The Securities Information Processors (''SIPs''), which include the Unlisted Trading Privileges and the Consolidated Tape Association, collect fees from

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] The Exchange initially filed the proposed pricing change on April 1, 2024 (SR–Phlx–2024–16). On April 15, 2024, the Exchange withdrew that filing and submitted SR–Phlx–2024–17. On April 25, 2024, the Exchange withdrew that filing and submitted this filing.

subscribers for trade and quote tape data received from trading centers and reporting facilities, such as the Exchange (collectively ''SIP Participants''). After deducting the cost of operating each tape, the profits are allocated among the SIP Participants on a quarterly basis, according to a complex set of calculations that consider estimates of anticipated MDR, adjustments to comport to actual MDR from previous quarters and a non-linear aggregation of total trading and quoting activity in Tape A, B and C securities in attributing MDR to each SIP Participant. Based on these calculations, the SIPs provide MDR payments to each SIP Participant during the first month of each quarter for trade and quote data from the previous calendar quarter, which are subject to adjustment through subsequent quarterly payments. These payments can be divided into six pools (*i.e.,* trade and quote activity in Tape A, B and C securities).

Proposed PSX MDR Rebate Program

As the Exchange does not currently share MDR with Participants, the Exchange now proposes to implement a PSX MDR Rebate program to share MDR attributed to quote activity only by adopting a PSX MDR Rebate program in Equity 7, Section 3.

Specifically, proposed Section (a) provides that, assuming that the requirements of this PSX MDR Rebate Section are met, a PSX Participant may receive a quarterly MDR rebate in proportion to the PSX Participant's quoting of displayed orders in Tape A and C securities from the previous calendar quarter (''MDR Rebate''), as described further in Section (e).

Proposed Section (b) provides that, to qualify for the MDR Rebate, a PSX Participant must quote at the National Best Bid or Offer (''NBBO'') at least 25% of the time during Market Hours in an average of at least 250 securities for Tape A securities or at least 300 securities for Tape C securities through the PSX Participant's MPID. A PSX Participant is considered to be quoting at the NBBO if the PSX Participant's MPID quotes a displayed order of at least 100 shares in the security and prices the order at either the national best bid or the national best offer or both the national best bid and offer for the security. To qualify for the MDR Rebate, the PSX Participant must meet the requirement for an average of at least 250 securities for Tape A securities or at least 300 securities for Tape C securities per day over the course of the quarter.

Proposed Section (c) provides that MDR will be calculated separately for quotes in each Tape A and C security, for a total of two MDR pools. If the MDR received by the Exchange in any given pool exceeds the following thresholds in any given calendar quarter, 40% of such excess MDR will be payable to PSX Participants in proportion to their respective quoting of displayed orders in that pool:

Tape A	Tape C
$110,000	$200,000

The proposed thresholds were selected based on historical data of PSX's quoting revenue from Q2 2023–Q4 2023. The dollar values represent the amount of MDR that must be paid to the Exchange by the SIPs before the Excess MDR would be eligible for distribution.

The Exchange proposes to adopt two of the six MDR pools utilized by the SIPs, excluding the pools for trading activity and the pool for quoting activity in Tape B, and attributing the proposed MDR Rebates to PSX Participants for quote activity in Tapes A and C. Currently, PSX Participants are most actively quoting Tape B securities on PSX. The Exchange proposes to establish the MDR Rebates for quoting activity in Tapes A and C because the Exchange wants to encourage increased quoting at the NBBO for Tapes A and C.

Section (d) provides a *de minimis* requirement that states that a PSX Participant will not receive an MDR Rebate in any calendar quarter in which the total MDR Rebate attributed to the PSX Participant is less than $500. If a PSX Participant is eligible for MDR Rebates from both pools, the PSX Participant will be eligible to receive an MDR rebate equal to the sum of the rebates. However, if the sum of the rebates is less than $500, the PSX Participant will not receive a payment and the rebate will be kept by the Exchange. The purpose of the *de minimis* requirement is to encourage significant quote activity and for the Exchange to avoid having to pay PSX Participants for *de minimis* Excess MDR.[4]

In attributing eligible quote activity to PSX Participants, the Exchange proposes to utilize a set of calculations similar to those used by the SIPs in allocating MDR to SIP Participants. Section (e) of the proposed rule language describes the steps for calculating MDR Rebates:

Step 1. Calculate, on a daily basis (per MPID), the product of three factors: number of shares in the quotation, the duration of the quotation at the NBBO (for both the bid and the offer), and the price of the security.

Step 2. For each security, sum the daily values from Step 1 across the quarter, the sum of which represents the PSX Participant's quote credits (per MPID) in each security.

Step 3. For each security, sum all PSX Participants' quote credits to obtain the total quote credits available per security.

Step 4. Divide each PSX Participant's quote credits (per MPID) (from Step 2) into the total quote credits available per security (from Step 3) to obtain a Participant's percentage of the security they are quoting (per MPID).

Step 5. Calculate the income allocation weight for each security based on the share of revenue allocated to the symbol by the SIP that quarter.

Step 6. For each security, multiply a PSX Participant's percentage of security they are quoting (per MPID) (from Step 4) by the income allocation weight of the security (from Step 5).

Step 7. For each PSX Participant's MPID, sum the values calculated in Step 6 across all securities in the pool (*i.e.,* in the same Tape) to obtain the PSX Participant's allocation percentage for the excess MDR in the pool.

Step 8. For each PSX Participant with eligible quote activity in the pool, multiply the PSX Participant's allocation percentage (from Step 7) by the excess MDR in the pool to determine the dollar amount of the PSX Participant's MDR Rebate in the pool.

As for calculating the pool of funds from which MDR Rebates will be paid, unlike the SIPs, the Exchange will derive MDR Rebate allocation from a fixed value that will not be subject to adjustment (*i.e.,* the amount of MDR actually received by the Exchange on a quarterly basis). This avoids the problem of having to adjust MDR rebates that have already been paid to PSX Participants to comport to adjustments to MDR made by the SIPs.[5]

The following *Example,* which the Exchange provides in the proposed rule language, illustrates how Excess MDR will be calculated and distributed:

Step 1. On the first day of the quarter, PSX Participant A earns 59,000 quote

[4] For example, it would be unduly burdensome to the Exchange to calculate and pay MDR Rebates to PSX Participants if the total Excess MDR of all the pools was $4000 and ten PSX Participants were each attributed $400 in rebates.

[5] For example, if MDR paid to the Exchange was less than anticipated in Q3 2024 due to an adjustment to the MDR paid to the Exchange in Q2 2024 (*i.e.,* actual MDR in Q2 fell short of estimates), the Exchange will not recoup the difference from the PSX Participants that had been paid the Q2 MDR Rebate. Instead, the MDR Rebate for Q3 will be calculated based on the actual MDR paid to the Exchange in Q3.

credits in MPID 1 for Security X (a Tape C security): 59 seconds x $10 x 100 shares.

Step 2. Assume PSX Participant A earns 4,000,000 quote credits for Security X in MPID 1 after summing its daily quote credits across the quarter.

Step 3. Assume there are five PSX Participants (*i.e.,* Participants A, B, C, D and E) that had eligible quote activity in Security X during the quarter. The quarterly quote credits for Security X are as follows:

Participant	Security X Quote Credits
A	4,000,000
B	1,000,000
C	3,500,000
D	2,500,000
E	5,000,000
Total	16,000,000

Step 4. PSX Participant A's percentage of Security X it quoted is 25%: 4,000,000/16,000,000.

Step 5. Assume the SIP allocated revenue of $360,000 to Security X for the quarter and $36,000,000 to all securities in the Tape C pool for the quarter. The income allocation weight for security X is 1%: $360,000/ $36,000,000.

Step 6. PSX Participant A's allocation percentage for the excess MDR in Security X in MPID 1 is 0.25%: 25% x 1%.

Step 7. Assume, after summing the allocation percentage calculated in Step 6 across all securities in the Tape C pool, PSX Participant A's allocation percentage is 2.5% in MPID 1.

Step 8. Assume PSX Participant A quoted at the NBBO at least 25% of the time during Market Hours in an average of at least 300 securities in Tape C through MPID 1, in accordance with section (b) above.

The following table represents the proposed MDR pool thresholds:

Tape A	Tape C
$110,000	$200,000

Under this Example, assume that the quarterly MDR paid to the Exchange is apportioned as follows:

Tape A	Tape C
$110,000	$350,000

Under this Example, the Tape C pool has excess MDR in the amount of $150,000. However, the Tape A pool has no excess MDR because the actual MDR received in the Tape A pool was equal to its $110,000 threshold. Thus, PSX Participants may be paid MDR Rebates for attributed eligible quoting activity from 40% of the excess MDR in the Tape C pool, which is $60,000.

The attributed MDR for PSX Participant A in MPID 1 is $1,500: 2.5% × 60,000. Sincethe attributed MDR is greater than $500, PSX Participant A would receive an MDRpayment in the amount of $1,500.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[6] in general, and furthers the objectives of Sections 6(b)(4) and 6(b)(5) of the Act,[7] in particular, in that it provides for the equitable allocation of reasonable dues, fees and other charges among members and issuers and other persons using any facility, and is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

The Exchange's proposed changes to its schedule of credits are reasonable in several respects. As a threshold matter, the Exchange is subject to significant competitive forces in the market for equity securities transaction services that constrain its pricing determinations in that market. The fact that this market is competitive has long been recognized by the courts. In *NetCoalition* v. *Securities and Exchange Commission,* the D.C. Circuit stated as follows: ''[n]o one disputes that competition for order flow is 'fierce.' . . . As the SEC explained, '[i]n the U.S. national market system, buyers and sellers of securities, and the broker-dealers that act as their order-routing agents, have a wide range of choices of where to route orders for execution'; [and] 'no exchange can afford to take its market share percentages for granted' because 'no exchange possesses a monopoly, regulatory or otherwise, in the execution of order flow from broker dealers'. . ..'' [8]

The Commission and the courts have repeatedly expressed their preference for competition over regulatory intervention in determining prices, products, and services in the securities markets. In Regulation NMS, while adopting a series of steps to improve the current market model, the Commission highlighted the importance of market forces in determining prices and SRO revenues and, also, recognized that current regulation of the market system ''has been remarkably successful in promoting market competition in its broader forms that are most important to investors and listed companies.'' [9]

Numerous indicia demonstrate the competitive nature of this market. For example, clear substitutes to the Exchange exist in the market for equity security transaction services. The Exchange is only one of several equity venues to which market participants may direct their order flow. Competing equity exchanges offer similar tiered pricing structures to that of the Exchange, including schedules of rebates and fees that apply based upon members achieving certain volume thresholds.

Within this environment, market participants can freely and often do shift their order flow among the Exchange and competing venues in response to changes in their respective pricing schedules. As such, the proposal represents a reasonable attempt by the Exchange to increase its liquidity and market share relative to its competitors.

The Exchange believes it is reasonable, equitable, and not unfairly discriminatory for the Exchange to adopt a PSX MDR Rebate program that provides for sharing of Excess MDR with PSX Participants in proportion to their respective eligible quoting activity in Tape A and C securities, as described above. The Exchange believes the proposal is reasonable as it will provide an incentive for PSX Participants to increase quoting in displayed liquidity in Tape A and C securities on the Exchange. An increase in displayed liquidity and order flow to the Exchange will, in turn, improve the quality of the market and increase its attractiveness to existing and prospective participants. In addition, the proposal is equitable and not unfairly discriminatory as the proposal would equitably allocate MDR Rebates among PSX Participants by paying MDR Rebates according to the total quoting activity in Tape A and C securities attributable to a PSX Participant in any given calendar quarter. The MDR Rebates are available to all PSX Participants.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

[6] 15 U.S.C. 78f(b).

[7] 15 U.S.C. 78f(b)(4) and (5).

[8] *NetCoalition* v. *SEC,* 615 F.3d 525, 539 (D.C. Cir. 2010) (quoting Securities Exchange Act Release No. 59039 (December 2, 2008), 73 FR 74770, 74782–83 (December 9, 2008) (SR–NYSEArca–2006–21)).

[9] Securities Exchange Act Release No. 51808 (June 9, 2005), 70 FR 37496, 37499 (June 29, 2005) (''Regulation NMS Adopting Release'').

Intramarket Competition

The Exchange does not believe that its proposal will place any category of Exchange participant at a competitive disadvantage.

As noted above, the Exchange's proposal is intended to have market-improving effects, by increasing displayed liquidity and order flow to the Exchange, to the benefit of all participants. The Exchange notes that its participants are free to trade on other venues to the extent they believe that the proposal is not attractive. As one can observe by looking at any market share chart, price competition between exchanges is fierce, with liquidity and market share moving freely between exchanges in reaction to fee and credit changes.

Intermarket Competition

In terms of inter-market competition, the Exchange notes that it operates in a highly competitive market in which market participants can readily favor competing venues if they deem fee levels at a particular venue to be excessive, or rebate opportunities available at other venues to be more favorable. In such an environment, the Exchange must continually adjust its credits and fees to remain competitive with other exchanges and with alternative trading systems that have been exempted from compliance with the statutory standards applicable to exchanges. Because competitors are free to modify their own credits and fees in response, and because market participants may readily adjust their order routing practices, the Exchange believes that the degree to which credit or fee changes in this market may impose any burden on competition is extremely limited. The proposal is reflective of this competition.

Even the largest U.S. equities exchange by volume has less than 20% market share, which in most markets could hardly be categorized as having enough market power to burden competition. Moreover, as noted above, price competition between exchanges is fierce, with liquidity and market share moving freely between exchanges in reaction to fee and credit changes. This is in addition to free flow of order flow to and among off-exchange venues which comprises upwards of 50% of industry volume.

In sum, if the change proposed herein is unattractive to market participants, it is likely that the Exchange will lose market share as a result. Accordingly, the Exchange does not believe that the proposed change will impair the ability of members or competing order execution venues to maintain their competitive standing in the financial markets.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act.[10]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is: (i) necessary or appropriate in the public interest; (ii) for the protection of investors; or (iii) otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's internet comment form (*https://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include file number SR–Phlx–2024–18 on the subject line.

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549–1090.

All submissions should refer to file number SR–Phlx–2024–18. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's internet website (*https://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Room, 100 F Street NE, Washington, DC 20549 on official business days between the hours of 10:00 a.m. and 3:00 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. Do not include personal identifiable information in submissions; you should submit only information that you wish to make available publicly. We may redact in part or withhold entirely from publication submitted material that is obscene or subject to copyright protection. All submissions should refer to file number SR–Phlx–2024–18, and should be submitted on or before May 30, 2024.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[11]

J. Matthew DeLesDernier,

Deputy Secretary.

[FR Doc. 2024–10081 Filed 5–8–24; 8:45 am]

BILLING CODE 8011–01–P

[10] 15 U.S.C. 78s(b)(3)(A)(ii).

[11] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–100061; File No. SR–Phlx–2024–22]

Self-Regulatory Organizations; Nasdaq PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Trade Now Order Attribute, at Equity 4, Rule 3301B and Rule 3301A

May 3, 2024.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on April 30, 2024, Nasdaq PHLX LLC (''Phlx'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the Trade Now Order Attribute, at Equity 4, Rule 3301B,[3] as well as to make conforming changes to Rule 3301A, as described further below.

The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/phlx/rules,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Rule 3301B(l), which governs the Trade Now Order Attribute.[4] Under the Exchange's rules, as amended by SR-Phlx-2023–43,[5] Trade Now is an Attribute that allows a resting Order ''that becomes locked or crossed, as applicable, at its non-displayed price by the posted price of an incoming Displayed Order or a Midpoint Peg Post-Only Order to execute against the locking or crossing Order(s) as a liquidity taker automatically.'' The Exchange proposes to amend this rule text to state instead that Trade Now allows ''a resting Order that is locked or crossed, as applicable, at its non-displayed price by the posted price of an incoming Displayed Order or a Midpoint Peg Post-Only Order or another Order or Orders (where such locking or crossing Order(s) or the order with Trade Now satisfies a Minimum Quantity condition) to execute against a locking or crossing Order(s) as a liquidity taker automatically, when such Orders become marketable.'' These proposed amendments serve several purposes.

First, the proposed amended text broadens the scope of the Rule so that it provides for Trade Now to also activate in circumstances where Orders possessing the Trade Now Order Attribute cannot execute at the point of initial interaction due to a Minimum Quantity condition[6] on the resting Order. The existing rule text suggests that Trade Now will activate only where it can do so immediately upon interaction with an incoming Displayed Order or a Midpoint Peg Post-Only Order, rather than after waiting for any conditions that preclude immediate execution from occurring. Under the proposed amendment, Trade Now would activate and execute against the locking or crossing Orders when the Minimum Quantity condition that prevented the immediate execution is satisfied, provided that the other requirements for activation of Trade Now functionality remain satisfied at that time.[7]

This proposed amendment enables Trade Now to better achieve its underlying purpose—which is to help clear the Exchange Book of locking or crossing orders. The Exchange perceives no logical basis to preclude activation of Trade Now when two (or more) Orders meet the conditions for activation, but for the fact that one of them has a Minimum Quantity condition that precluded it from executing (immediately upon entry and/or against subsequent incoming contra-side orders). Provided that the conditions for Trade Now to activate remain satisfied as of the time when the Orders become marketable, the Exchange believes that it is logical and consistent with the purpose of Trade Now for these Orders to execute such locking or crossing orders when the Minimum Quantity condition can be satisfied because doing so will help clear the Order Book of locked and crossed orders.

An example of a scenario in which the proposed amendment would apply is when an Order with Trade Now has a Minimum Quantity condition that a locking or crossing Order cannot initially satisfy. By way of illustration, assume that Participant A enters Order 1, which is a Displayed Order to sell 100 shares of XYZ at $10.00. Participant B then enters Order 2, which is a Non-Displayed Trade Now order to buy 200 shares of XYZ at $10.00, with a Minimum Quantity requirement of 200 shares. Order 2 will not automatically remove Order 1 due to the Minimum Quantity requirement. Participant C thereafter enters Order 3, which is a Non-Displayed Order to sell 100 shares of XYZ at $10.00. Under the existing Rule, Order 2 would not remove Order 3 using Trade Now due to the Minimum Quantity requirement of Order 2. Under the proposed amended Rule text, however, Trade Now would be activated for Order 2, and it would remove both Orders 1 and 3.

Similarly, the amendment would apply when it is an incoming locking Order, or a resting locking Order, that has a Minimum Quantity condition which the Order with Trade Now cannot satisfy immediately. In this scenario, assume that Participant A enters Order 1, which is a Non-Displayed Order to sell 300 shares of XYZ at $10.00, with a Minimum Quantity requirement of 200 shares. Participant B then enters Order 2, which is a Non-Displayed Order with Trade Now to buy 100 shares of XYZ at $10.00. Under the existing Rule, Order 2 will lock Order 1 but not execute due to the Minimum Quantity requirement associated with Order 1. If Participant C thereafter enters Order 3, which is another Displayed Order to buy 200 shares of XYZ at $10.00, then under the existing Rule, Order 3 will execute against Order 1 upon receipt, but Order 2 will not use Trade Now to trade against the remaining shares of Order 1. Under the proposal, however, once Order 3 is entered, it will execute against Order 1, satisfying the Minimum Quantity requirement of Order 1 and reducing the remaining size of Order 1 to 100 shares. At this point, Order 2 is capable of executing against the reduced size of Order 1. Order 2 will activate Trade Now, execute against Order 1, and clear the locked book.

In addition to the above, the proposed amendments to Rule 3301B(l), along

[3] References herein to Phlx Rules in the 3000 Series shall mean Rules in Phlx Equity 4.

[4] An ''Order Attribute'' is a further set of variable instructions that may be associated with an Order to further define how it will behave with respect to pricing, execution, and/or posting to the Exchange Book when submitted to the Exchange. *See id.*

[5] *See* Securities Exchange Act Release No. 34–98377 (September 13, 2023); 88 FR 64504 (September 19, 2023) (SR–Phlx–2023–43).

[6] Pursuant to Rule 3301B(e), ''Minimum Quantity'' is an Order Attribute that allows a Participant to provide that an Order will not execute unless a specified minimum quantity of shares can be obtained. The Rule provides for two types of Minimum Quantity Attributes: one in which a participant specifies that the condition may be satisfied by execution against one or more orders with an aggregate size of at least the minimum quantity; and another in which the condition must be satisfied by execution against one or more Orders, each of which must have a size of at least the minimum quantity. *Id.* This proposed rule change concerns the first of these two alternatives.

[7] The Proposal also replaces the word ''becomes'' with ''is'' in the existing phrase ''resting Order that becomes locked or crossed, as applicable, at its non-displayed price'' to accommodate the fact that, with the proposed amendment, Trade Now could activate after an Order with Trade Now becomes locked if it is not marketable at that initial point in time.

with corresponding amendments to Rule 3301A(b)(4) and (6), would discontinue the applicability of Trade Now to Midpoint Peg Post-Only Orders and Post-Only Orders.[8] The Exchange proposes to eliminate the applicability of Trade Now to these two Order Types because Trade Now is incompatible with the designs of these Order Types. In other words, Midpoint Peg Post-Only Orders and Post-Only Orders are liquidity-adding Order Types, whereas Orders with Trade Now are designed to be liquidity taking Orders. Because of this incompatibility, the Exchange finds that market participants rarely, as a practical matter, select Trade Now for their Midpoint Peg Post-Only Orders or their Post-Only Orders. Insofar as Trade Now serves no apparent utility as an Attribute of these Order Types, the Exchange proposes to eliminate its applicability thereto.

Lastly, the Exchange proposes to modify existing language in the Rule which states that only an incoming Displayed Order whose displayed price locks or crosses a resting Order with Trade Now at its non-displayed price, or an incoming Midpoint Peg Post-Only Order, will trigger the Trade Now functionality. The proposed Rule amendment broadens this text to also provide for another Order (including a Displayed or a Non-Displayed Order) whose price locks or crosses a resting Order with Trade Now to trigger Trade Now where the resting Order with Trade Now has a Minimum Quantity condition that the incoming Order (either itself, or in aggregate with other resting Orders) satisfies. The purpose of this new language is to account for the fact that a non-Displayed incoming Order, in addition to a Displayed incoming Order, can lock or cross a resting Order with Trade Now if it satisfies the Minimum Quantity condition of the resting Trade Now Order. The proposed amended Rule text also accounts for scenarios in which the Order with Trade Now does not possess a Minimum Quantity condition, but instead, the incoming locking/crossing Order or another resting locking/crossing Order possesses the Minimum Quantity Attribute, and the Minimum Quantity condition is reduced such that the Order with Trade Now becomes able to satisfy the condition. The proposed amendments would provide for Trade Now to activate in these scenarios as well.

The Exchange will publish an Equity Trader Alert at least seven days prior to implementing the proposed amendments.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[9] in general, and further the objectives of Section 6(b)(5) of the Act,[10] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest.

Specifically, the Exchange believes that it is consistent with the Act to amend the Exchange's Trade Now Rule to allow for Trade Now to activate, not only immediately upon receipt of a locking or crossing contra Displayed or Midpoint Peg Post-Only Order, but also at such time when the Order with Trade Now become marketable, if it was not marketable initially due to a Minimum Quantity Condition. The Exchange believes that the proposed behavior is consistent with the underlying intent of Trade Now, which is to help to clear the Exchange's Order Book of locking and crossing Orders. The Exchange perceives no logical basis to preclude activation of Trade Now when two Orders meet the conditions for activation, but for the fact that one of them is not marketable, and thus cannot interact with the other one immediately upon entry. Provided that the conditions for Trade Now to activate remain satisfied as of the time when the Orders become marketable, the Exchange believes that these Orders should execute automatically at that time. Moreover, the Exchange believes that the proposed behavior is consistent with the expectations of market participants for Trade Now functionality.

In addition to the above, it is also consistent with the Act to amend Rule 3301B(l), along with Rule 3301A(b)(4) and (6), to discontinue the applicability of Trade Now to Midpoint Peg Post-Only Orders and Post-Only Orders. As noted above, the Exchange proposes to eliminate the applicability of Trade Now to these two Order Types because Trade Now, which classifies an Order as a liquidity taker, is incompatible with the designs of these Order Types as liquidity maker Orders. Insofar as Trade Now serves no apparent utility as an Attribute of these Order Types, it is reasonable and in the interests of the markets and investors to eliminate its applicability thereto.

Lastly, the Exchange believes it is consistent with the Act to modify existing language in the Rule which states that only an incoming Displayed Order whose displayed price locks or crosses a resting Order with Trade Now at its non-displayed price, or an incoming Midpoint Peg Post-Only Order, will trigger the Trade Now functionality. As stated above, the proposed Rule amendment broadens this text to also provide for another Order (including a Displayed or a Non-Displayed Order) whose price locks or crosses a resting Order with Trade Now to trigger Trade Now where the resting Order with Trade Now has a Minimum Quantity condition that the incoming Order satisfies. This new language would account for the fact that a non-Displayed incoming Order, in addition to a Displayed incoming Order, can lock or cross a resting Order with Trade Now if it satisfies the Minimum Quantity condition. The proposed amended Rule text also accounts for scenarios in which the Order with Trade Now does not possess a Minimum Quantity condition, but instead, the incoming locking/crossing Order or another resting locking/crossing Order possesses the Minimum Quantity Attribute, and the Minimum Quantity condition is reduced such that the Order with Trade Now becomes able to satisfy the condition. The proposed amendments would provide for Trade Now to activate in these scenarios as well. Again, no purpose is served by excluding these scenarios from triggering Trade Now. To the contrary, including them would further the purpose of Trade Now, which is to aid in the clearing the Exchange's Order Book of locked and crossing Orders.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule changes will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. Although the proposal will broaden the applicability of Trade Now, the Exchange neither intends nor perceives that this rule change will have any significant impact on competition other than to make the Exchange's Trade Now Attribute more useful for participants, and thus the Exchange a more attractive venue in which to trade. Even as amended, Trade Now will remain an optional functionality that the Exchange offers at no charge, and which may be used equally by similarly-situated participants.

[8] The existing rule text of Rule 3301B(l) expressly applies Trade Now to Midpoint Peg Post-Only Orders, and implicitly applies Trade Now to Post-Only Orders by virtue of Trade Now's applicability to Displayed Orders (Post-Only Orders are Displayed).

[9] 15 U.S.C. 78f(b).

[10] 15 U.S.C. 78f(b)(5).

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A)(iii) of the Act[11] and subparagraph (f)(6) of Rule 19b–4 thereunder.[12]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's internet comment form (*https://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include file number SR–Phlx–2024–22 on the subject line.

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549–1090.

All submissions should refer to file number SR-Phlx-2024–22. This file number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's internet website (*https://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Room, 100 F Street NE, Washington, DC 20549 on official business days between the hours of 10:00 a.m. and 3:00 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. Do not include personal identifiable information in submissions; you should submit only information that you wish to make available publicly. We may redact in part or withhold entirely from publication submitted material that is obscene or subject to copyright protection. All submissions should refer to file number SR-Phlx-2024–22, and should be submitted on or before May 30, 2024.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[13]

J. Matthew DeLesDernier,

Deputy Secretary.

[FR Doc. 2024–10082 Filed 5–8–24; 8:45 am]

BILLING CODE 8011–01–P

[11] 15 U.S.C. 78s(b)(3)(A)(iii).

[12] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[13] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–100059; File No. SR–BX–2024–013]

Self-Regulatory Organizations; Nasdaq BX, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Trade Now Order Attribute at Equity 4, Rule 4702 and Make Conforming Changes to Rule 4703

May 3, 2024.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on April 26, 2024, Nasdaq BX, Inc. (''BX'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the Trade Now Order Attribute, at Equity 4, Rule 4702,[3] as well as to make conforming changes to Rule 4703, as described further below.

The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/nasdaq/rules,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Rule 4703(l), which governs the Trade Now Order Attribute.[4] Under the Exchange's rules, as amended by SR–BX–2022–015,[5] Trade Now is an Attribute that allows a resting Order ''that becomes locked or crossed, as applicable, at its non-displayed price by the posted price of an incoming Displayed Order to execute against a

[3] References herein to BX Rules in the 4000 Series shall mean Rules in BX Equity 4.

[4] An ''Order Attribute'' is a further set of variable instructions that may be associated with an Order to further define how it will behave with respect to pricing, execution, and/or posting to the Exchange Book when submitted to the Exchange. *See id.*

[5] *See* Securities Exchange Act Release No. 34–95695 (September 7, 2022); 87 FR 56122 (September 13, 2022) (SR–BX–2022–015).

locking or crossing Orders as a liquidity taker automatically.'' The Exchange proposes to amend this rule text to state instead that Trade Now allows ''a resting Order that is locked or crossed, as applicable, at its non-displayed price by the posted price of an incoming Displayed Order or another Order or Orders (where such locking or crossing Order(s) or the order with Trade Now satisfies a Minimum Quantity condition) to execute against a locking or crossing Order(s) as a liquidity taker automatically, when such Orders become marketable.'' These proposed amendments serve several purposes.

First, the proposed amended text broadens the scope of the Rule so that it provides for Trade Now to also activate in circumstances where Orders possessing the Trade Now Order Attribute cannot execute at the point of initial interaction due to a Minimum Quantity condition [6] on the resting Order. The existing rule text suggests that Trade Now will activate only where it can do so immediately upon interaction with an incoming Displayed Order, rather than after waiting for any conditions that preclude immediate execution from occurring. Under the proposed amendment, Trade Now would activate and execute against the locking or crossing Orders when the Minimum Quantity condition that prevented the immediate execution is satisfied, provided that the other requirements for activation of Trade Now functionality remain satisfied at that time.[7]

This proposed amendment enables Trade Now to better achieve its underlying purpose—which is to help clear the Exchange Book of locking or crossing orders. The Exchange perceives no logical basis to preclude activation of Trade Now when two (or more) Orders meet the conditions for activation, but for the fact that one of them has a Minimum Quantity condition that precluded it from executing (immediately upon entry and/or against subsequent incoming contra-side orders). Provided that the conditions for Trade Now to activate remain satisfied as of the time when the Orders become marketable, the Exchange believes that it is logical and consistent with the purpose of Trade Now for this Order to execute such locking or crossing orders when the Minimum Quantity condition can be satisfied because doing so will help clear the Order Book of locked and crossed orders.

An example of a scenario in which the proposed amendment would apply is when an Order with Trade Now has a Minimum Quantity condition that a locking or crossing Order cannot initially satisfy. By way of illustration, assume that Participant A enters Order 1, which is a Displayed Order to sell 100 shares of XYZ at $10.00. Participant B then enters Order 2, which is a Non-Displayed Trade Now order to buy 200 shares of XYZ at $10.00, with a Minimum Quantity requirement of 200 shares. Order 2 will not automatically remove Order 1 due to the Minimum Quantity requirement. Participant C thereafter enters Order 3, which is a Non-Displayed Order to sell 100 shares of XYZ at $10.00. Under the existing Rule, Order 2 would not remove Order 3 using Trade Now due to the Minimum Quantity requirement of Order 2. Under the proposed amended Rule text, however, Trade Now would be activated for Order 2, and it would remove both Orders 1 and 3.

Similarly, the amendment would apply when it is an incoming locking Order, or a resting locking Order, that has a Minimum Quantity condition which the Order with Trade Now cannot satisfy immediately. In this scenario, assume that Participant A enters Order 1, which is a Non-Displayed Order to sell 300 shares of XYZ at $10.00, with a Minimum Quantity requirement of 200 shares. Participant B then enters Order 2, which is a Non-Displayed Order with Trade Now to buy 100 shares of XYZ at $10.00. Under the existing Rule, Order 2 will lock Order 1 but not execute due to the Minimum Quantity requirement associated with Order 1. If Participant C thereafter enters Order 3, which is another Displayed Order to buy 200 shares of XYZ at $10.00, then under the existing Rule, Order 3 will execute against Order 1 upon receipt, but Order 2 will not use Trade Now to trade against the remaining shares of Order 1. Under the proposal, however, once Order 3 is entered, it will execute against Order 1, satisfying the Minimum Quantity requirement of Order 1 and reducing the remaining size of Order 1 to 100 shares. At this point, Order 2 is capable of executing against the reduced size of Order 1. Order 2 will activate Trade Now, execute against Order 1, and clear the locked book.

In addition to the above, the proposed amendments to Rule 4703(l), along with corresponding amendments to Rule 4702(b)(4)(C), would discontinue the applicability of Trade Now to Post-Only Orders.[8] The Exchange proposes to eliminate the applicability of Trade Now to this Order Type because Trade Now is incompatible with the designs of this Order Type. In other words, Post-Only Orders are liquidity-adding Order Type, whereas Orders with Trade Now are designed to be liquidity taking Orders. Because of this incompatibility, the Exchange finds that market participants rarely, as a practical matter, select Trade Now for their Post-Only Orders. Insofar as Trade Now serves no apparent utility as an Attribute of this Order Type, the Exchange proposes to eliminate its applicability thereto.

Lastly, the Exchange proposes to modify existing language in the Rule which states that only an incoming Displayed Order whose displayed price locks or crosses a resting Order with Trade Now at its non-displayed price will trigger the Trade Now functionality. The proposed Rule amendment broadens this text to also provide for another Order (including a Displayed or a Non-Displayed Order) whose price locks or crosses a resting Order with Trade Now to trigger Trade Now where the resting Order with Trade Now has a Minimum Quantity condition that the incoming Order (either itself, or in aggregate with other resting Orders) satisfies. The purpose of this new language is to account for the fact that a non-Displayed incoming Order, in addition to a Displayed incoming Order, can lock or cross a resting Order with Trade Now if it satisfies the Minimum Quantity condition of the resting Trade Now Order. The proposed amended Rule text also accounts for scenarios in which the Order with Trade Now does not possess a Minimum Quantity condition, but instead, the incoming locking/crossing Order or another resting locking/crossing Order possesses the Minimum Quantity Attribute, and the Minimum Quantity condition is reduced such that the Order with Trade Now becomes able to satisfy the condition. The proposed amendments

[6] Pursuant to Rule 4703(e), ''Minimum Quantity'' is an Order Attribute that allows a Participant to provide that an Order will not execute unless a specified minimum quantity of shares can be obtained. The Rule provides for two types of Minimum Quantity Attributes: one in which a participant specifies that the condition may be satisfied by execution against one or more orders with an aggregate size of at least the minimum quantity; and another in which the condition must be satisfied by execution against one or more Orders, each of which must have a size of at least the minimum quantity. *Id.* This proposed rule change concerns the first of these two alternatives.

[7] The Proposal also replaces the word ''becomes'' with ''is'' in the existing phrase ''resting Order that becomes locked or crossed, as applicable, at its non-displayed price'' to accommodate the fact that, with the proposed amendment, Trade Now could activate after an Order with Trade Now becomes locked if it is not marketable at that initial point in time.

[8] The existing rule text of Rule 4703(l) expressly applies Trade Now to Post-Only Orders by virtue of Trade Now's applicability to Displayed Orders (Post-Only Orders are Displayed).

would provide for Trade Now to activate in these scenarios as well.

The Exchange will publish an Equity Trader Alert at least seven days prior to implementing the proposed amendments.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[9] in general, and further the objectives of Section 6(b)(5) of the Act,[10] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest.

Specifically, the Exchange believes that it is consistent with the Act to amend the Exchange's Trade Now Rule to allow for Trade Now to activate, not only immediately upon receipt of a locking or crossing contra Displayed Order, but also at such time when the Order with Trade Now become marketable, if it was not marketable initially due to a Minimum Quantity Condition. The Exchange believes that the proposed behavior is consistent with the underlying intent of Trade Now, which is to help to clear the Exchange's Order Book of locking and crossing Orders. The Exchange perceives no logical basis to preclude activation of Trade Now when two Orders meet the conditions for activation, but for the fact that one of them is not marketable, and thus cannot interact with the other one immediately upon entry. Provided that the conditions for Trade Now to activate remain satisfied as of the time when the Orders become marketable, the Exchange believes that these Orders should execute automatically at that time. Moreover, the Exchange believes that the proposed behavior is consistent with the expectations of market participants for Trade Now functionality.

In addition to the above, it is also consistent with the Act to amend Rule 4703(l), along with Rule 4702(b)(4)(C), to discontinue the applicability of Trade Now to Post-Only Orders. As noted above, the Exchange proposes to eliminate the applicability of Trade Now to this Order Type because Trade Now, which classifies an Order as a liquidity taker, is incompatible with the designs of this Order Type as liquidity maker Orders. Insofar as Trade Now serves no apparent utility as an Attribute of this Order Type, it is reasonable and in the interests of the markets and investors to eliminate its applicability thereto.

Lastly, the Exchange believes it is consistent with the Act to modify existing language in the Rule which states that only an incoming Displayed Order whose displayed price locks or crosses a resting Order with Trade Now at its non-displayed price will trigger the Trade Now functionality. As stated above, the proposed Rule amendment broadens this text to also provide for another Order (including a Displayed or a Non-Displayed Order) whose price locks or crosses a resting Order with Trade Now to trigger Trade Now where the resting Order with Trade Now has a Minimum Quantity condition that the incoming Order satisfies. This new language would account for the fact that a non-Displayed incoming Order, in addition to a Displayed incoming Order, can lock or cross a resting Order with Trade Now if it satisfies the Minimum Quantity condition. The proposed amended Rule text also accounts for scenarios in which the Order with Trade Now does not possess a Minimum Quantity condition, but instead, the incoming locking/crossing Order or another resting locking/crossing Order possesses the Minimum Quantity Attribute, and the Minimum Quantity condition is reduced such that the Order with Trade Now becomes able to satisfy the condition. The proposed amendments would provide for Trade Now to activate in these scenarios as well. Again, no purpose is served by excluding these scenarios from triggering Trade Now. To the contrary, including them would further the purpose of Trade Now, which is to aid in the clearing the Exchange's Order Book of locked and crossing Orders.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule changes will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. Although the proposal will broaden the applicability of Trade Now, the Exchange neither intends nor perceives that this rule change will have any significant impact on competition other than to make the Exchange's Trade Now Attribute more useful for participants, and thus the Exchange a more attractive venue in which to trade. Even as amended, Trade Now will remain an optional functionality that the Exchange offers at no charge, and which may be used equally by similarly-situated participants.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A)(iii) of the Act[11] and subparagraph (f)(6) of Rule 19b–4 thereunder.[12]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's internet comment form (*https://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include file number SR–BX–2024–013 on the subject line.

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549–1090.

All submissions should refer to file number SR–BX–2024–013. This file

[9] 15 U.S.C. 78f(b).

[10] 15 U.S.C. 78f(b)(5).

[11] 15 U.S.C. 78s(b)(3)(A)(iii).

[12] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

number should be included on the subject line if email is used. To help the Commission process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's internet website (*https://www.sec.gov/rules/sro.shtml*). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for website viewing and printing in the Commission's Public Reference Room, 100 F Street NE, Washington, DC 20549 on official business days between the hours of 10:00 a.m. and 3:00 p.m. Copies of the filing also will be available for inspection and copying at the principal office of the Exchange. Do not include personal identifiable information in submissions; you should submit only information that you wish to make available publicly. We may redact in part or withhold entirely from publication submitted material that is obscene or subject to copyright protection. All submissions should refer to file number SR–BX–2024–013, and should be submitted on or before May 30, 2024.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[13]

J. Matthew DeLesDernier,

Deputy Secretary.

[FR Doc. 2024–10080 Filed 5–8–24; 8:45 am]

BILLING CODE 8011–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #20288 and #20289; LOUISIANA Disaster Number LA–20003]

Administrative Declaration of a Disaster for the State of LOUISIANA

AGENCY: Small Business Administration.

ACTION: Notice.

SUMMARY: This is a notice of an Administrative declaration of a disaster for the State of LOUISIANA dated 05/03/2024.

Incident: Severe Storm, Flooding, Straight-line Winds and Tornadoes.

Incident Period: 04/10/2024.

DATES: Issued on 05/03/2024.

Physical Loan Application Deadline Date: 07/02/2024.

Economic Injury (EIDL) Loan Application Deadline Date: 02/03/2025.

ADDRESSES: *Visit the MySBA Loan Portal at https://lending.sba.gov* to apply for a disaster assistance loan.

FOR FURTHER INFORMATION CONTACT: Alan Escobar, Office of Disaster Recovery & Resilience, U.S. Small Business Administration, 409 3rd Street SW, Suite 6050, Washington, DC 20416, (202) 205–6734.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the Administrator's disaster declaration, applications for disaster loans may be submitted online using the MySBA Loan Portal *https://lending.sba.gov* or other locally announced locations. Please contact the SBA disaster assistance customer service center by email at *disastercustomerservice@sba.gov* or by phone at 1–800–659–2955 for further assistance.

The following areas have been determined to be adversely affected by the disaster:

Primary Parishes: St. Tammany

Contiguous Parishes/Counties:

Louisiana: Jefferson, Orleans, Tangipahoa, Washington

Mississippi: Hancock, Pearl River

The Interest Rates are:

	Percent
For Physical Damage:	
Homeowners with Credit Available Elsewhere	5.375
Homeowners without Credit Available Elsewhere	2.688
Businesses with Credit Available Elsewhere	8.000
Businesses without Credit Available Elsewhere	4.000
Non-Profit Organizations with Credit Available Elsewhere	3.250
Non-Profit Organizations without Credit Available Elsewhere	3.250
For Economic Injury:	
Business and Small Agricultural Cooperatives without Credit Available Elsewhere	4.000
Non-Profit Organizations without Credit Available Elsewhere	3.250

The number assigned to this disaster for physical damage is 20288C and for economic injury is 202890.

The States which received an EIDL Declaration are Louisiana, Mississippi.

(Catalog of Federal Domestic Assistance Number 59008)

Isabella Guzman,

Administrator.

[FR Doc. 2024–10088 Filed 5–8–24; 8:45 am]

BILLING CODE 8026–09–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #20258; MARYLAND Disaster Number MD–20001 Declaration of Economic Injury]

Administrative Declaration of an Economic Injury Disaster for the State of MARYLAND; Correction

AGENCY: Small Business Administration.

ACTION: Correction.

SUMMARY: This is a correction to the Administrative Economic Injury Disaster Loan (EIDL) declaration for the State of MARYLAND dated 03/29/2024. This catastrophe has far-ranging effects for businesses throughout the state, surrounding areas and are of national scale and significance.

Incident: Francis Scott Key Bridge Collapse.

Incident Period: 03/26/2024 and continuing.

DATES: Issued on 05/03/2024.

Economic Injury (EIDL) Loan Application Deadline Date: 12/30/2024.

ADDRESSES: *Visit the MySBA Loan Portal at https://lending.sba.gov* to apply for a disaster assistance loan.

FOR FURTHER INFORMATION CONTACT: Alan Escobar, Office of Disaster Recovery & Resilience, U.S. Small Business Administration, 409 3rd Street SW, Suite 6050, Washington, DC 20416, (202) 205–6734.

SUPPLEMENTARY INFORMATION: The notice of the Administrator's EIDL disaster declaration for the State of Maryland, dated 03/29/2024, published at 89 FR 23616, is hereby corrected to include King George, Northumberland, Prince William, Stafford, and Westmoreland Counties in Virginia as contiguous counties. Applications for disaster loans may be submitted online using the MySBA Loan Portal *https://lending.sba.gov* or other locally announced locations. Please contact the SBA disaster assistance customer service center by email at *disastercustomerservice@sba.gov* or by phone at 1–800–659–2955 for further assistance.

The following areas have been determined to be adversely affected by the disaster:

Primary Counties: Allegany, Anne Arundel, Baltimore, Baltimore, Calvert, Caroline, Carroll, Cecil, Charles, Dorchester, Frederick, Garrett, Harford, Howard, Kent, Montgomery, Prince George's, Queen Anne's, Somerset, St. Mary's, Talbot, Washington, Wicomico, Worcester.

Contiguous Counties:

Delaware: Kent, New Castle, Sussex

[13] 17 CFR 200.30–3(a)(12).

District of Columbia: District Of Columbia
Pennsylvania: Adams, Bedford, Chester, Fayette, Franklin, Fulton, Lancaster, Somerset, York.
Virginia: Accomack, Alexandria, Arlington, Fairfax County, King George, Loudoun, Northumberland, Prince William, Stafford, Westmoreland.
West Virginia: Berkeley, Grant, Hampshire, Jefferson, Mineral, Morgan, Preston.

The Interest Rates are:

	Percent
Business and Small Agricultural Cooperatives without Credit Available Elsewhere	4.000
Non-Profit Organizations without Credit Available Elsewhere	3.250

The number assigned to this disaster for economic injury is 202580.

The States which received an EIDL Declaration are Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia.

(Catalog of Federal Domestic Assistance Number 59008)

Isabella Guzman,

Administrator.

[FR Doc. 2024–10087 Filed 5–8–24; 8:45 am]

BILLING CODE 8026–09–P

DEPARTMENT OF STATE

[Public Notice: 12399]

Notice of Department of State Sanctions Actions

ACTION: Notice.

SUMMARY: The U.S. Department of State's Office of Economic Sanctions Policy and Implementation (SPI) is publishing the name of one vessel that has been removed from the List of Specially Designated Nationals and Blocked Persons (SDN List) maintained by the Office of Foreign Assets Control (OFAC) and is consequently no longer subject to the prohibitions imposed pursuant to the Executive Order, ''Blocking Property With Respect To Specified Harmful Foreign Activities of the Government of the Russian Federation.''

DATES: The actions described in this notice were effective on August 3, 2023.

FOR FURTHER INFORMATION CONTACT: Aaron P. Forsberg, Director, Office of Economic Sanctions Policy and Implementation, Bureau of Economic and Business Affairs, Department of State, Washington, DC 20520, tel.: (202) 647–7677, email: *forsbergap@state.gov*.

SUPPLEMENTARY INFORMATION:

Electronic Availability

The SDN List and additional information concerning OFAC sanctions programs are available from OFAC's website at *http://www.treasury.gov/ofac*.

Notice of Department of State Actions

On August 3, 2023, OFAC removed from the SDN List the vessel listed below, which was subject to prohibitions imposed pursuant to E.O. 14024 of April 15, 2021.

Entity

1. ADDICTION (9HA4571) Yacht Malta flag; Vessel Year of Build 2010; Vessel Registration Identification IMO 1010193; MMSI 248233000 (vessel) [RUSSIA–EO14024] (Linked To: ADONEV, Sergei Nikolaevich).

Amy E. Holman,

Principal Deputy Assistant Secretary, Bureau of Economic and Business Affairs, Department of State.

[FR Doc. 2024–10085 Filed 5–8–24; 8:45 am]

BILLING CODE 4710–07–P

STATE JUSTICE INSTITUTE

SJI Board of Directors Meeting, Notice

AGENCY: State Justice Institute.

ACTION: Notice of meeting.

SUMMARY: The purpose of this meeting is to consider grant applications for the 3rd quarter of FY 2024, and other business.

DATES: The SJI Board of Directors will be meeting on Monday, June 3, 2024 at 1:00 p.m. ET.

ADDRESSES: Michigan Hall of Justice, 925 West Ottawa Street, Lansing, Michigan.

FOR FURTHER INFORMATION CONTACT: Jonathan Mattiello, Executive Director, State Justice Institute, 12700 Fair Lakes Circle, Suite 340, Fairfax, VA 22033, 703–660–4979, *contact@sji.gov*.

(Authority: 42 U.S.C. 10702(f))

Jonathan D. Mattiello,

Executive Director.

[FR Doc. 2024–10138 Filed 5–8–24; 8:45 am]

BILLING CODE 6820–SC–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

[Docket No. FHWA–2024–0035]

Agency Information Collection Activities: Request for Comments for a New Information Collection

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice and request for comments.

SUMMARY: The FHWA invites public comments about our intention to request the Office of Management and Budget's (OMB) approval for a new information collection, which is summarized below under **SUPPLEMENTARY INFORMATION**. We are required to publish this notice in the **Federal Register** by the Paperwork Reduction Act of 1995.

DATES: Please submit comments by July 8, 2024.

ADDRESSES: You may submit comments identified by DOT Docket ID Number 0035 by any of the following methods:

Website: For access to the docket to read background documents or comments received go to the Federal eRulemaking Portal: Go to *http://www.regulations.gov*. Follow the online instructions for submitting comments.

Fax: 1–202–493–2251.

Mail: Docket Management Facility, U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590–0001.

Hand Delivery or Courier: U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590, between 9 a.m. and 5 p.m. ET, Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Frances Ramirez, (202) 961–8605 FHWA, Office of Federal Lands Highway, Office of Federal Lands Programs, 22001 Loudoun County Parkway, Building E1, Suite 150, Ashburn, VA 20147. Office hours are from 8 a.m. to 4 p.m., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

Title: Nationally Significant Federal Lands and Tribal Projects (NSFLTP) Program.

Background: The NSFLTP Program was authorized under section 1123 of the Fixing America's Surface Transportation (FAST) Act (Pub. L. 114–94) and amended by section 11127 of the BIL. The NSFLTP Program funds are to be awarded on a competitive basis for the construction, reconstruction, and

rehabilitation of nationally significant projects within, adjacent to, or accessing Federal and Tribal lands. The NSFLTP Program provides an opportunity to address significant challenges across the Nation for transportation facilities that serve Federal and Tribal lands.

Respondents: Eligible applicants include Federal Land Management Agencies (FLMA); Tribal governments; and States, counties, and units of local government may also apply, but only if sponsored by an FLMA or Tribal government.

Activity: Notice of Funding Opportunity (NOFO).

Application Frequency: The application package is annually following the instructions of the NOFO.

Estimated Average Burden per Response: On average, addressing the criteria requested on the NOFO may take 5 hours to complete.

Estimated Total Annual Burden Hours: Total estimated average annual burden is 110 hours.

Activity: Executing Grant Agreement

Application Frequency: A successful grant recipient requires an executed grant agreement to receive the NSFLTP funding.

Estimated Average Burden per Response: On average, completing and executing a grant agreement may take 3 hours to complete.

Estimated Total Annual Burden Hours: Total estimated burden is 54 hours.

Activity: Post Award Reporting

Application Frequency: if the grant recipient is a State or a Tribal government, the project performance report is submitted every six months (biannually). If the grant recipient is and FLMA, the project performance report is submitted every three months (quarterly).

Estimated Average Burden per Response: On average, the project performance report may take 1 hours to complete.

Estimated Total Annual Burden Hours: Total estimated average annual burden is 50 hours. Per the activities described above, the total estimated burden is 214 hours annually.

Public Comments Invited: You are asked to comment on any aspect of this information collection, including: (1) Whether the proposed collection is necessary for the FHWA's performance; (2) the accuracy of the estimated burdens; (3) ways for the FHWA to enhance the quality, usefulness, and clarity of the collected information; and (4) ways that the burden could be minimized, including the use of electronic technology, without reducing the quality of the collected information. The agency will summarize and/or include your comments in the request for OMB's clearance of this information collection.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. chapter 35, as amended; and 49 CFR 1.48.

Issued on: March 6, 2024.

Jazmyne Lewis,

Information Collection Officer.

[FR Doc. 2024–10140 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–22–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

[Docket No. FHWA–2024–0037]

Agency Information Collection Activities: Request for Comments for a New Information Collection

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice and request for comments.

SUMMARY: The FHWA invites public comments about our intention to request the Office of Management and Budget's (OMB) approval for a new information collection, which is summarized below under **SUPPLEMENTARY INFORMATION**. We are required to publish this notice in the **Federal Register** by the Paperwork Reduction Act of 1995.

DATES: Please submit comments by July 8, 2024.

ADDRESSES: You may submit comments identified by DOT Docket ID Number 0037 by any of the following methods:

Website: For access to the docket to read background documents or comments received go to the Federal eRulemaking Portal: Go to *http://www.regulations.gov.*

Follow the online instructions for submitting comments.

Fax: 1–202–493–2251.

Mail: Docket Management Facility, U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590–0001.

Hand Delivery or Courier: U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590, between 9 a.m. and 5 p.m. ET, Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Julie Johnston, (202) 591–5858, Office of Preconstruction, Construction and Pavements, Federal Highway Administration, Department of Transportation, 1200 New Jersey Avenue SE, Washington, DC 20590. Office hours are from 7 a.m. to 4 p.m., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

Title: Annual Value Engineering Call for Data.

Background: Value Engineering (VE) is defined as a systematic process of review and analysis of a project, during the concept and design phases, by a multidiscipline team of persons not involved in the project, that is conducted to provide recommendations for providing the needed functions safely, reliably, efficiently, and at the lowest overall cost; improving the value and quality of the project; and reducing the time to complete the project. Applicable projects requiring a VE analysis include Projects on the National Highway System (NHS) receiving Federal assistance with an estimated total cost of $50,000,000 or more; Bridge projects on the NHS receiving Federal assistance with an estimated total cost of $40,000,000 or more; any major project, as defined in 23 U.S.C. 106(h), located on or off the NHS, that utilizes Federal-aid highway funding in any contract or phase; and other projects as defined in 23 CFR 627.5. 23 U.S.C. 106(e)(4)(iv) and 23 CFR 627.7(3) require States to monitor, evaluates and annually submit a report that describes the results of the value analyses that are conducted, and the recommendations implemented on applicable projects. The FHWA Annually submits a National Call for VE Data in order to monitor and assess the VE Program and meet the requirements of 23 U.S.C. 106(h).

Respondents: 52, including 50 State Transportation Departments, the District of Columbia, the Commonwealth of Puerto Rico.

Frequency: Once per year.

Estimated Average Burden per Response: Approximately 2 hours per participant over a year.

Estimated Total Annual Burden Hours: Approximately 104 hours per year.

Public Comments Invited: You are asked to comment on any aspect of this information collection, including: (1) Whether the proposed collection is necessary for the FHWA's performance; (2) the accuracy of the estimated burdens; (3) ways for the FHWA to enhance the quality, usefulness, and clarity of the collected information; and (4) ways that the burden could be minimized, including the use of

electronic technology, without reducing the quality of the collected information. The agency will summarize and/or include your comments in the request for OMB's clearance of this information collection.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. chapter 35, as amended; and 49 CFR 1.48.

Issued on: May 6, 2024.

Jazmyne Lewis,

Information Collection Officer.

[FR Doc. 2024–10150 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–22–P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA–2023–0057]

Commercial Driver's License Standards: Application for Exemption; Pitt Ohio Express, LLC

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of final disposition; denial of application for exemption.

SUMMARY: FMCSA announces its denial of the application from Pitt Ohio Express, LLC (Pitt Ohio) to exempt its drivers from one of the requirements in the Agency's Safe Driver Apprenticeship Pilot (SDAP) program. Pitt Ohio requests an exemption allowing it to use drivers under the age 21, who hold a Commercial Learner's Permit (CLP) to operate commercial motor vehicles (CMVs) in interstate commerce, to participate in the SDAP program. FMCSA analyzed the application and determined that there is insufficient basis to conclude that the exemption would likely achieve a level of safety that is equivalent to, or greater than, the level that would be achieved absent such exemption.

FOR FURTHER INFORMATION CONTACT: Mr. Richard Clemente, Driver and Carrier Operations Division; Office of Carrier, Driver and Vehicle Safety Standards; FMCSA; (202) 366–2722; *richard.clemente@dot.gov*. If you have questions on viewing or submitting material to the docket, contact Dockets Services at (202) 366–9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation

Viewing Comments and Documents

To view comments, go to *www.regulations.gov,* insert the docket number ''FMCSA–2023–0057'' in the keyword box, and click ''Search.'' Next, sort the results by ''Posted (Newer-Older),'' choose the first notice listed, click ''Browse Comments.''

To view documents mentioned in this notice as being available in the docket, go to *www.regulations.gov,* insert the docket number ''FMCSA–2023–0057'' in the keyword box, click ''Search,'' and chose the document to review.

If you do not have access to the internet, you may view the docket online by visiting Dockets Operations on the ground floor of the DOT West Building, 1200 New Jersey Avenue SE, Washington, DC 20590, between 9 a.m. and 5 p.m., ET, Monday through Friday, except Federal holidays. To be sure someone is there to help you, please call (202) 366–9317 or (202) 366–9826 before visiting Dockets Operations.

II. Legal Basis

FMCSA has authority under 49 U.S.C. 31136(e) and 31315(b) to grant exemptions from Federal Motor Carrier Safety Regulations (FMCSRs). FMCSA must publish a notice of each exemption request in the **Federal Register** (49 CFR 381.315(a)). The Agency must provide the public an opportunity to inspect the information relevant to the application, including any safety analyses that have been conducted. The Agency must provide an opportunity for public comment on the request.

The Agency reviews safety analyses and public comments submitted and determines whether granting the exemption would likely achieve a level of safety equivalent to, or greater than, the level that would be achieved by the current regulation (49 CFR 381.305(a)). The Agency must publish its decision in the **Federal Register** (49 CFR 381.315(b)). If granted, the notice will identify the regulatory provision from which the applicant will be exempt, the effective period, and all terms and conditions of the exemption (49 CFR 381.315(c)(1)). If the exemption is denied, the notice will explain the reason for the denial (49 CFR 381.315(c)(2). The exemption may be renewed (49 CFR 381.300(b)).

III. Background

Current Regulations

Under 49 CFR 391.11(b)(1) a person may not drive a (CMV) in interstate commerce unless they are at least 21 years old, regardless of whether operation of the CMV requires a commercial driver's license (CDL). Additionally, for drivers under 21 operating CMVs requiring a CLP or CDL, under 49 CFR 383.153(b)(2)(ix)(G), an intrastate only ''K'' restriction must appear on the individual's CLP or CDL.

Safe Driver Apprenticeship Pilot Program

The SDAP program allows registered motor carriers to use apprentice drivers who are 18 to 20 years old under certain circumstances. Apprentice drivers under the SDAP program must hold a CDL and complete separate 120- and 280-hour probationary periods during their apprenticeship with registered motor carriers. (87 FR 2477).

Applicant's Request

Pitt Ohio is a less-than-truckload regional carrier which operates multiple straight trucks. The applicant seeks an exemption from the requirement in the Agency's SDAP program that an apprentice hold a CDL prior to enrolling in the program. Pitt Ohio requests the exemption to allow it to use CLP holders in the SDAP Program. These CLP holders would still need to meet all the remaining apprentice requirements, as well as the existing regulatory requirements for CLP holders (*e.g.,* presence of a valid CDL holder in the passenger seat). Pitt Ohio estimates that 25 CLP holders would operate under the exemption each year. The applicant believes the exemption would relieve them of ''difficulty locating and recruiting apprentice drivers into [the] SDAP Program.''

Applicant's Method To Ensure an Equivalent or Greater Level of Safety

According to Pitt Ohio, CLP drivers operating under the exemption would be as safe or safer than those currently allowed to operate under the SDAP program. Pitt Ohio asserts that the CLP driver operating under the exemption will be safer and more productive due to being trained initially in a smaller CMV so the apprentice can learn and gain an understanding of the industry with the same equipment and oversight from an experienced and approved FMCSA trainer before graduating into larger equipment for the post-CDL aspect of the SDAP program. Pitt Ohio did not ask for any exemption to the level of safety required under the current SDAP program and indicated that they would meet or exceed all hours of training and technology on the CMVs the apprentice would operate. Pitt Ohio would be voluntarily applying SDAP program requirements to the pre-CDL portion of driver development and training, and in addition would report all progress of the program as required and any additional requirements that may be requested by FMCSA to meet the exemption request.

IV. Public Comments

On February 23, 2023, FMCSA published notice of the Pitt Ohio application and requested public comments (88 FR 11504). The Agency was seeking comment on whether this exemption should be limited to Pitt Ohio, or whether it should be drafted to apply to any SDAP program participating motor carrier that is currently listed as a certified training provider for purposes of the FMCSRs, or that enters into a partnership with a certified training provider. On this question, one individual responded, ''I am all for this plan, so long as you make the training program universal for everyone.'' The Agency received a total of 23 comments: 4 supporting the exemption request, 16 opposing it, and the other 3 taking no position either for or against. Joint comments filed by the Truck Safety Coalition, Citizens for Reliable and Safe Highways (CRASH), and Parents Against Tired Truckers (PATT) stated ''Pitt-Ohio(sic) Express, LLC has not met the measure of evidence required to prove an equivalent or greater level of safety in its exemption application. They only request that FMCSA dilute the program requirements in misplaced efforts to make it easier to attract under-21 drivers.'' Edward Richard opposed the application and stated ''allowing them to put more immature drivers on the road is just wrong and unsafe.'' AWM Associates, LLC also opposed, noting that ''until Pitt-Ohio(sic) is an approved CDL training provider on the FMCSA's Training Provider Registry (TPR) its petition must be denied.'' Those in support commented that the Pitt Ohio request should be made universal for everyone, that age should not matter, and that the Agency should use great caution in implementing the exemption should it be granted.

V. FMCSA's Decision

FMCSA has evaluated Pitt Ohio's application and the filed comments and finds that there is insufficient basis to conclude that the exemption would likely achieve a level of safety equivalent to, or greater than, the level achieved without the exemption. The SDAP's purpose is to determine whether there are conditions where safety data indicate younger drivers (18- to 20-year-olds) might be allowed to operate CMVs. Congress authorized SDAP, opening the pilot to those 18- to 20-year-olds who hold a CDL, not a CLP. In addition, granting the Pitt Ohio exemption could potentially put young and inexperienced drivers in a position of high responsibility, potentially exposing them and surrounding drivers to crashes and incidents involving CMVs. The Agency therefore believes that Pitt Ohio's prospective apprentice CLP drivers should not be legally permitted to operate CMVs in interstate commerce if less than 21 years of age.

For the above reasons, FMCSA denies Pitt Ohio's exemption application.

Sue Lawless,

Acting Deputy Administrator.

[FR Doc. 2024–10077 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

[Docket Number FRA–2024–0043]

Petition for Waiver of Compliance

Under part 211 of title 49 Code of Federal Regulations (CFR), this document provides the public notice that on March 13, 2024, Rapid City, Pierre & Eastern Railroad and the International Association of Sheet Metal, Air, Rail and Transportation Workers (collectively, ''Petitioners''), petitioned the Federal Railroad Administration (FRA) for a waiver of compliance from certain provisions of the Federal railroad safety regulations contained at 49 CFR part 240 (Qualification and Certification of Locomotive Engineers) and part 242 (Qualification and Certification of Conductors). FRA assigned the petition Docket Number FRA–2024–0043.

Specifically, Petitioners request relief required to participate in FRA's Confidential Close Call Reporting System (C^{3}RS) Program. Petitioners seek to shield reporting employees from mandatory punitive sanctions that would otherwise arise as provided in §§ 240.117(e)(1)–(4); 240.305(a)(1)–(4) and (a)(6); 240.307; 242.403(b), (c), (e)(1)–(4), (e)(6)–(11), (f)(1)–(2); and 242.407. The C^{3}RS Program encourages certified operating crew members to report close calls and protects the employees and the railroad from discipline or sanctions arising from the incidents reported per the C^{3}RS Implementing Memorandum of Understanding.

A copy of the petition, as well as any written communications concerning the petition, is available for review online at *www.regulations.gov.*

Interested parties are invited to participate in these proceedings by submitting written views, data, or comments. FRA does not anticipate scheduling a public hearing in connection with these proceedings since the facts do not appear to warrant a hearing. If any interested parties desire an opportunity for oral comment and a public hearing, they should notify FRA, in writing, before the end of the comment period and specify the basis for their request.

All communications concerning these proceedings should identify the appropriate docket number and may be submitted at *www.regulations.gov.* Follow the online instructions for submitting comments.

Communications received by July 8, 2024 will be considered by FRA before final action is taken. Comments received after that date will be considered if practicable.

Anyone can search the electronic form of any written communications and comments received into any of our dockets by the name of the individual submitting the comment (or signing the document, if submitted on behalf of an association, business, labor union, etc.). Under 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its processes. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *https://www.transportation.gov/privacy.* See also *https://www.regulations.gov/privacy-notice* for the privacy notice of regulations.gov.

Issued in Washington, DC.

John Karl Alexy,

Associate Administrator for Railroad Safety, Chief Safety Officer.

[FR Doc. 2024–10178 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–06–P

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

[Docket Number FRA–2003–15010]

Petition for Extension of Waiver of Compliance

Under part 211 of title 49 Code of Federal Regulations (CFR), this document provides the public notice that on February 28, 2024, CPKC [1] petitioned the Federal Railroad Administration (FRA) for an extension of a waiver of compliance from certain provisions of the Federal railroad safety regulations contained at 49 CFR part

[1] On April 14, 2023, Canadian Pacific Railway Company (CP) and Kansas City Southern (KCS) combined to create a single railway company doing business under the trademark CPKC. The original waiver in this docket was granted to CP.

241 (United States Locational Requirements for Dispatching of United States Rail Operations). The relevant Docket Number is FRA–2003–15010.

Specifically, CPKC requests an extension of relief pursuant to 49 CFR 241.7(c), *Fringe border dispatching,* to allow the continuation of Canadian dispatching of three locations in the United States: (1) 1.8 miles of the Windsor Subdivision between Windsor, Ontario, Canada, and Detroit, Michigan, United States; [2] and (2) two track segments totaling 23.44 miles on the Newport Subdivision between Richford, Vermont, and East Richford, Vermont, United States, and between North Troy, Vermont, and Newport, Vermont, United States.[3] CPKC notes that all locations are dispatched by the Operations Centre in Calgary, Alberta, Canada. In support of its request, CPKC states that ''in the approximately twenty-one years since the original waiver was granted, CPKC has operated safely on the Windsor Subdivision and has operated safely on the Newport Subdivision since the acquisition of this territory in 2020.'' CPKC adds that it ''is not aware of any issues that have developed since the last waiver was granted.''

A copy of the petition, as well as any written communications concerning the petition, is available for review online at *www.regulations.gov.*

Interested parties are invited to participate in these proceedings by submitting written views, data, or comments. FRA does not anticipate scheduling a public hearing in connection with these proceedings since the facts do not appear to warrant a hearing. If any interested party desires an opportunity for oral comment and a public hearing, they should notify FRA, in writing, before the end of the comment period and specify the basis for their request.

All communications concerning these proceedings should identify the appropriate docket number and may be submitted at *https://www.regulations.gov.* Follow the online instructions for submitting comments.

Communications received by July 8, 2024 will be considered by FRA before final action is taken. Comments received after that date will be considered if practicable. Anyone can search the electronic form of any written communications and comments received into any of our dockets by the name of the individual submitting the comment (or signing the document, if submitted on behalf of an association, business, labor union, etc.). Under 5 U.S.C. 553(c), the U.S. Department of Transportation (DOT) solicits comments from the public to better inform its processes. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *https://www.transportation.gov/privacy.* See also *https://www.regulations.gov/privacy-notice* for the privacy notice of regulations.gov.

Issued in Washington, DC.

John Karl Alexy,

Associate Administrator for Railroad Safety, Chief Safety Officer.

[FR Doc. 2024–10179 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–06–P

DEPARTMENT OF TRANSPORTATION

Federal Railroad Administration

[Docket Number FRA–2003–15012]

Petition for Extension of Waiver of Compliance

Under part 211 of title 49 Code of Federal Regulations (CFR), this document provides the public notice that on February 28, 2024, Canadian National Railway Company (CN) petitioned the Federal Railroad Administration (FRA) for an extension of a waiver of compliance from certain provisions of the Federal railroad safety regulations contained at 49 CFR part 241 (United States Locational Requirements for Dispatching of United States Rail Operations). The relevant FRA Docket Number is FRA–2003–15012.Specifically, CN requests an extension of relief pursuant to 49 CFR 241.7(c), *Fringe border dispatching,* to allow the continuation of Canadian dispatching of two locations in the United States: the portion of the Sprague Subdivision extending approximately 43.8 miles between Baudette and International Boundary, Minnesota, and the portion of the Strathroy Subdivision extending approximately 3.1 miles between Sarnia, Ontario, Canada, through the St. Clair River Tunnel, to Port Huron, Michigan.[1] In support of its request, CN states that, since the initial waiver was granted, ''each of these fringe border segments ha[ve] been regularly and safety dispatched from Canada'' and this extension would allow CN to ''continue what it has been safely doing for decades.'' CN explains that changing dispatching to the United States on this section of the Sprague Subdivision ''would introduce two [dispatching] hand-offs, given that the track only briefly enters the United States before re-entering Canada.'' Additionally, in reference to the portion of track on the Strathroy Subdivision, CN states that grating the waiver extension ''avoids any risk or safety concern associated with a [dispatching] hand-off in the middle of a single-track underwater tunnel.''

A copy of the petition, as well as any written communications concerning the petition, is available for review online at *www.regulations.gov.*

Interested parties are invited to participate in these proceedings by submitting written views, data, or comments. FRA does not anticipate scheduling a public hearing in connection with these proceedings since the facts do not appear to warrant a hearing. If any interested party desires an opportunity for oral comment and a public hearing, they should notify FRA, in writing, before the end of the comment period and specify the basis for their request.

All communications concerning these proceedings should identify the appropriate docket number and may be submitted at *https://www.regulations.gov.* Follow the online instructions for submitting comments.

Communications received by July 8, 2024 will be considered by FRA before final action is taken. Comments received after that date will be considered if practicable. Anyone can search the electronic form of any written communications and comments received into any of our dockets by the name of the individual submitting the comment (or signing the document, if submitted on behalf of an association, business, labor union, etc.). Under 5 U.S.C. 553(c), the U.S. Department of Transportation (DOT) solicits comments from the public to better inform its processes. DOT posts these comments, without edit, including any personal information the commenter provides, to *www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *https://www.transportation.gov/privacy.* See also *https://www.regulations.gov/*

[2] This section on the Windsor Subdivision is defined in appendix A to part 241, *List of Lines Being Extraterritorially Dispatched in Accordance with the Regulations Contained in 49 CFR part 241, Revised as of October 1, 2002.*

[3] The track segments on the Newport Subdivision cross the U.S./Canada border at three separate locations.

[1] Both of these locations are defined in appendix A to part 241, *List of Lines Being Extraterritorially Dispatched in Accordance with the Regulations Contained in 49 CFR part 241, Revised as of October 1, 2002.*

privacy-notice for the privacy notice of regulations.gov.

Issued in Washington, DC.

John Karl Alexy,

Associate Administrator for Railroad Safety, Chief Safety Officer.

[FR Doc. 2024–10177 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–06–P

DEPARTMENT OF THE TREASURY

Office of Foreign Assets Control

Notice of OFAC Sanctions Action

AGENCY: Office of Foreign Assets Control, Treasury.

ACTION: Notice.

SUMMARY: The U.S. Department of the Treasury's Office of Foreign Assets Control (OFAC) is publishing the name of a person whose property and interests in property have been unblocked and who has been removed from the Specially Designated Nationals and Blocked Persons List (SDN List). OFAC is also publishing a removal of aircraft currently identified on OFAC's SDN List.

DATES: See **SUPPLEMENTARY INFORMATION** section for effective date(s).

FOR FURTHER INFORMATION CONTACT: OFAC: Bradley T. Smith, Director, tel.: 202–622–2490; Associate Director for Global Targeting, tel.: 202–622–2420; Assistant Director for Licensing, tel.: 202–622–2480; Assistant Director for Regulatory Affairs, tel.: 202–622–4855; or the Assistant Director for Sanctions Compliance & Evaluation, tel.: 202–622–2490.

SUPPLEMENTARY INFORMATION:

Electronic Availability

The SDN List and additional information concerning OFAC sanctions programs are available on OFAC's website (*https://www.treasury.gov/ofac*).

Notice of OFAC Action(s)

A. On May 3, 2024, OFAC removed from the SDN List the person listed below, whose property and interests in property were blocked pursuant to section 1(a) of Executive Order 14024 of April 15, 2021, ''Blocking Property With Respect To Specified Harmful Foreign Activities of the Government of the Russian Federation,'' 86 FR 20249, 3 CFR, 2021 Comp., p. 542 (Apr. 15, 2021) (E.O. 14024). On May 3, 2024, OFAC determined that circumstances no longer warrant the inclusion of the following person on the SDN List under this authority. This person is no longer subject to the blocking provisions of section 1(a) of E.O. 14024.

1. EMPEROR AVIATION LTD (a.k.a. EMPEROR AVIEISHN LTD (Cyrillic: ЭМПЕРОР АВИЭЙШН ЛТД)), W Business Centre, Level 3, Triq Karmenu Pirotta, Birkirkara BKR 1114, Malta; Presnenskaya nab. 8/1, Moscow 123112, Russia; Organization Established Date 27 Nov 2013; Tax ID No. 21637116 (Malta); alt. Tax ID No. 9909425511 (Russia); Registration Number C 62836 (Malta) [RUSSIA–EO14024] (Linked To: KERIMOVA, Gulnara Suleymanovna).

B. On May 3, 2024, OFAC removed from the SDN List the aircraft listed below, which were subject to prohibitions imposed pursuant to E.O. 14024.

1. 9H–AMN; Aircraft Manufacture Date 2006; Aircraft Model BD–700–1A11; Aircraft Manufacturer's Serial Number (MSN) 9324; Aircraft Tail Number 9H–AMN (aircraft) [RUSSIA–EO14024] (Linked To: EMPEROR AVIATION LTD).

2. 9H–ARK; Aircraft Manufacture Date 2019; Aircraft Model BD–700–1A10; Aircraft Manufacturer's Serial Number (MSN) 60011; Aircraft Tail Number 9H–ARK (aircraft) [RUSSIA–EO14024] (Linked To: EMPEROR AVIATION LTD).

3. 9H–EAA; Aircraft Manufacture Date 2014; Aircraft Model Citation XLS+; Aircraft Manufacturer's Serial Number (MSN) 560–6170; Aircraft Tail Number 9H–EAA (aircraft) [RUSSIA–EO14024] (Linked To: EMPEROR AVIATION LTD).

4. 9H–MAO; Aircraft Manufacture Date 2006; Aircraft Model BD–700–1A10; Aircraft Manufacturer's Serial Number (MSN) 9223; Aircraft Tail Number 9H–MAO (aircraft) [RUSSIA–EO14024] (Linked To: EMPEROR AVIATION LTD).

5. 9H–SIS; Aircraft Manufacture Date 2015; Aircraft Model CL–600–2B16 (604 Variant); Aircraft Manufacturer's Serial Number (MSN) 6050; Aircraft Tail Number 9H–SIS (aircraft) [RUSSIA–EO14024] (Linked To: EMPEROR AVIATION LTD).

6. 9H–SSK; Aircraft Manufacture Date 2016; Aircraft Model G650; Aircraft Manufacturer's Serial Number (MSN) 6195; Aircraft Tail Number 9H–SSK (aircraft) [RUSSIA–EO14024] (Linked To: EMPEROR AVIATION LTD).

7. 9H–TIO; Aircraft Manufacture Date 2018; Aircraft Model BD–700–1A11; Aircraft Manufacturer's Serial Number (MSN) 9813; Aircraft Tail Number 9H–TIO (aircraft) [RUSSIA–EO14024] (Linked To: EMPEROR AVIATION LTD).

Dated: May 3, 2024.

Bradley T. Smith,

Director, Office of Foreign Assets Control, U.S. Department of the Treasury.

[FR Doc. 2024–10076 Filed 5–8–24; 8:45 am]

BILLING CODE 4810–AL–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

ETAAC Public Meeting Announcement

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice of meeting.

SUMMARY: The Electronic Tax Administration Advisory Committee (ETAAC) will hold a public meeting on Wednesday, June 26, 2024.

FOR FURTHER INFORMATION CONTACT: Mr. Alec Johnston, Office of National Public Liaison, at (202) 317–4299, or send an email to *publicliaison@irs.gov*

SUPPLEMENTARY INFORMATION: Notice is hereby given pursuant to 5 U.S.C. 10(a)(2) of the Federal Advisory Committee Act that a public meeting of the ETAAC will take place on Wednesday, June 26, 2024, from 9:00 a.m. to 11:00 a.m. EDT, at 1111 Constitution Ave. NW, in Washington, DC The purpose of the ETAAC is to provide continuing advice regarding the development and implementation of the IRS organizational strategy for electronic tax administration. ETAAC is an organized public forum for discussion of electronic tax administration issues such as prevention of identity theft and refund fraud. It supports the overriding goal that paperless filing should be the preferred and most convenient method of filing tax and information returns. ETAAC members convey the public's perceptions of IRS electronic tax administration activities, offer constructive observations about current or proposed policies, programs, and procedures, and suggest improvements. Please call or email Mr. Alec Johnston to confirm your attendance in person or by conference call or if you wish to submit a written statement. Mr. Johnston can be reached at 202–317–4299 or *PublicLiaison@irs.gov.*

Dated: May 6, 2024.

John A. Lipold,

Designated Federal Official, C&L Office of National Public Liaison, Internal Revenue Service.

[FR Doc. 2024–10146 Filed 5–8–24; 8:45 am]

BILLING CODE 4830–01–P

FEDERAL REGISTER

Vol. 89 Thursday,
No. 91 May 9, 2024

Part II

Department of Transportation

National Highway Traffic Safety Administration

49 CFR Parts 571, 595, and 596
Federal Motor Vehicle Safety Standards; Automatic Emergency Braking Systems for Light Vehicles; Final Rule

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Parts 571, 595, and 596

[Docket No. NHTSA–2023–0021]

RIN 2127–AM37

Federal Motor Vehicle Safety Standards; Automatic Emergency Braking Systems for Light Vehicles

AGENCY: National Highway Traffic Safety Administration (NHTSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: This final rule adopts a new Federal Motor Vehicle Safety Standard to require automatic emergency braking (AEB), including pedestrian AEB (PAEB), systems on light vehicles. An AEB system uses various sensor technologies and sub-systems that work together to detect when the vehicle is in a crash imminent situation, to automatically apply the vehicle brakes if the driver has not done so, or to apply more braking force to supplement the driver's braking. This final rule specifies that an AEB system must detect and react to an imminent crash with both a lead vehicle or a pedestrian. This final rule fulfills a mandate under the Bipartisan Infrastructure Law (BIL) directing the Department to promulgate a rule to require that all passenger vehicles be equipped with an AEB system. The purpose of this final rule is to reduce the number of deaths and injuries that result from crashes in which drivers do not apply the brakes or fail to apply sufficient braking power to avoid or mitigate a crash, and to reduce the consequences of such crashes.

DATES:

Effective Date: This rule is effective July 8, 2024.

IBR date: The incorporation by reference of certain material listed in the rule is approved by the Director of the **Federal Register** beginning July 8, 2024. The incorporation by reference of certain other material listed in the rule was approved by the Director of the Federal Register as of July 8, 2022.

Compliance Date: September 1, 2029. However, vehicles produced by small-volume manufacturers, final-stage manufacturers, and alterers must be equipped with a compliant AEB system by September 1, 2030.

Petitions for reconsideration: Petitions for reconsideration of this final rule must be received not later than June 24, 2024.

ADDRESSES: Petitions for reconsideration of this final rule must refer to the docket number set forth above (NHTSA–2023–0021) and be submitted to the Administrator, National Highway Traffic Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590.

FOR FURTHER INFORMATION CONTACT: *For technical issues:* Mr. Markus Price, Office of Crash Avoidance Rulemaking, Telephone: 202–366–1810, Facsimile: 202–366–7002. *For legal issues:* Ms. Sara R. Bennett, Office of the Chief Counsel, Telephone: 202–366–2992, Facsimile: 202–366–3820. The mailing address for these officials is: National Highway Traffic Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590.

SUPPLEMENTARY INFORMATION: This final rule adopts a new Federal Motor Vehicle Safety Standard (FMVSS) No. 127 to require automatic emergency braking (AEB), including pedestrian AEB (PAEB), systems on light vehicles. FMVSS No. 127 applies to all passenger cars and to all multipurpose passenger vehicles (MPVs), trucks, and buses with a gross vehicle weight rating (GVWR) of 4,536 kilograms (kg) (10,000 pounds (lbs.)) or less (''light vehicles''). An AEB system uses various sensor technologies and sub-systems that work together to detect when the vehicle is in a crash imminent situation, to automatically apply the vehicle brakes if the driver has not done so, or to apply more braking force to supplement the driver's braking.

This final rule specifies that an AEB system must detect and react to an imminent crash with both a lead vehicle and a pedestrian. This final rule advances DOT's January 2022 National Roadway Safety Strategy, which identified a requirement for AEB, including PAEB technologies, on new passenger vehicles as a key Departmental action to improve vehicle and pedestrian safety. Finally, this final rule fulfills section 24208(a) of BIL, which directs the Secretary of Transportation to promulgate a rule to require that all passenger vehicles be equipped with an AEB system.

NHTSA published the notice of proposed rulemaking preceding this final rule on June 13, 2023 (88 FR 38632).

Table of Contents

I. Executive Summary
II. Background
A. The Safety Problem
B. Bipartisan Infrastructure Law (BIL)
C. High-level Summary of Comments on the NPRM
D. Summary of the Notice of Proposed Rulemaking
E. Additional Research Conducted in 2023
III. Final Rule and Response to Comments
A. Summary of the Final Rule (and Modifications to the NPRM)
B. Application
C. Definitions
D. FCW and AEB Equipment Requirements
1. Minimum Activation Speed
2. Maximum Activation Speed
3. Environmental Conditions
E. AEB System Requirements (Applies to Lead Vehicle and Pedestrian)
1. Forward Collision Warning Requirements
a. FCW Signal Modality
b. FCW Auditory Signal Requirements
c. FCW Auditory Signal Presentation with Simultaneous Muting of Other In-Vehicle Audio
d. FCW Visual Symbol Requirements
e. FCW Visual Signal Location Requirements
2. AEB Requirement
a. AEB Deactivation
b. Aftermarket Modifications
c. No-Contact Requirement for Lead Vehicle AEB
d. No-Contact Requirement for Pedestrians
e. Permissibility of Failure
F. False Activation Requirement
1. Need for Requirement
2. Peak Additional Deceleration
3. Process Standard Documentation as Alternative to False Activation Requirements
4. Data Storage Requirement as Alternative to False Activation Requirements
G. Malfunction Detection Requirement
1. Need for Requirement
2. Malfunction Telltale
3. Sensor Obstructions and Testing
H. Procedure for Testing Lead Vehicle AEB
1. Scenarios
2. Subject Vehicle Speed Ranges
3. Headway
4. Lead Vehicle Deceleration
5. Manual Brake Application
6. Testing Setup and Completion
7. Miscellaneous Comments
I. Procedures for Testing PAEB
1. Scenarios
2. Subject Vehicle Speed Ranges
3. Pedestrian Test Device Speed
4. Overlap
5. Light Conditions
6. Testing Setup
J. Procedures for Testing False Activation
K. Track Testing Conditions
1. Environmental Test Conditions
2. Road/Test Track Conditions
L. Vehicle Test Device
1. General Description
2. Definitions
3. Sideview Specification
4. Field Verification Procedure
5. Dimensional Specification
6. Visual and Near Infrared Specification
7. Radar Reflectivity
8. List of Actual Vehicles
M. Pedestrian Test Devices
1. General Description
2. Dimensions and Posture
3. Visual Properties
4. Radar Properties

5. Articulation Properties
6. Comments on Thermal Characteristics
N. Miscellaneous Topics
O. Effective Date and Phase-In Schedule
IV. Summary of Estimated Effectiveness, Cost, and Benefits
A. Benefits
B. Costs
C. Net Impact
V. Regulatory Notices and Analyses
VI. Appendices to the Preamble
A. Appendix A: Description of the Lead Vehicle AEB Test Procedures
B. Appendix B: Description of the PAEB Test Procedures
C. Appendix C: Description of the False Activation Test Procedures

I. Executive Summary

In 2019, prior to the COVID–19 pandemic, there were nearly 2.2 million rear-end police-reported crashes involving light vehicles, which led to 1,798 deaths and 574,000 injuries. In addition, there were 6,272 pedestrian fatalities in motor vehicle crashes, representing 17 percent of all motor vehicle fatalities.[1] This represents the continuation of the recent trend of increased pedestrian deaths on our nation's roadways.[2] A further 76,000 pedestrians were injured in motor vehicle crashes. Deaths and injuries in more recent years are even greater.

NHTSA is issuing this final rule to address these significant safety problems through a new Federal Motor Vehicle Safety Standard that requires all light vehicles be equipped with forward collision warning (FCW),[3] automatic emergency braking (AEB), and pedestrian automatic emergency braking (PAEB) technology.[4] AEB systems reduce the frequency and severity of lead vehicle and pedestrian collisions. They employ sensor technologies and sub-systems that work together to sense when the vehicle is in a crash imminent situation, to automatically apply the vehicle brakes if the driver has not done so, and to apply more braking force to supplement the driver's braking. These systems can reduce both lead vehicle rear-end (lead vehicle AEB) and pedestrian (PAEB) crashes. AEB systems have reached a level of maturity to make a significant contribution to reducing the frequency and severity of crashes and are thus ready to be mandated through adoption of a new FMVSS on all new light vehicles.

This rule is estimated to save at least 362 lives and mitigate 24,321 non-fatal injuries a year. It represents a crucial step forward in implementing DOT's January 2022 National Roadway Safety Strategy (NRSS) to address the rising numbers of transportation deaths and serious injuries occurring on this country's roadways, including those involving pedestrians.[5]

The crash problem that the agency seeks to address with the AEB requirements in this final rule is substantial.[6] For example, 60 percent of fatal rear-end crashes and 73 percent of crashes resulting in injuries were on roads with posted speed limits of 60 mph or below. Similarly, most of these crashes occurred in clear, no adverse atmospheric conditions—72 percent of fatal crashes and 74 percent of crashes resulting in injuries. Also, about 51 percent of fatal rear-end crashes and 74 percent of rear-end crashes resulting in injuries, all involving light vehicles, occurred in daylight conditions. In addition, 65 percent of pedestrian fatalities and 67 percent of pedestrian injuries were the result of a strike by the front of a light vehicle. Finally, 77 percent of pedestrian fatalities, and about half of the pedestrian injuries, occur in dark lighting conditions. Importantly, this final rule requires that PAEB systems be able to avoid pedestrian crashes in dark testing conditions.

This final rule is issued under the authority of the National Traffic and Motor Vehicle Safety Act of 1966. Under 49 U.S.C. chapter 301, the Secretary of Transportation is responsible for prescribing motor vehicle safety standards that are practicable, meet the need for motor vehicle safety, and are stated in objective terms. The responsibility for promulgation of FMVSSs is delegated to NHTSA. This rulemaking addresses a statutory mandate under the Bipartisan Infrastructure Law (BIL), codified as the Infrastructure Investment and Jobs Act (IIJA),[7] which added 49 U.S.C. 30129, directing the Secretary of Transportation to promulgate a rule requiring that all passenger motor vehicles manufactured for sale in the United States be equipped with an FCW system and an AEB system.

The Focus on AEB

The decision to mandate AEB builds on decades of research and development, which began in the 1990s, with initial research programs to support development of AEB technologies and methods by which system performance could be assessed. NHTSA began testing AEB systems as part of the New Car Assessment Program (NCAP) in 2010 and reporting on the research and progress surrounding the technologies shortly thereafter.[8] These research efforts led to NHTSA listing FCW systems as a ''recommended advanced technology'' in NCAP in model year 2011, and in November 2015, added crash imminent braking (CIB) [9] and dynamic brake support (DBS) technologies to the program.[10] Most recently, NHTSA proposed upgrades to the lead vehicle AEB test in its March 2022 request for comment on NCAP.[11]

In March 2016, NHTSA and the Insurance Institute for Highway Safety (IIHS) announced a commitment by 20 manufacturers representing more than 99 percent of the U.S. light vehicle market to include low-speed AEB as a standard feature on nearly all new light vehicles not later than September 1,

[1] *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813079* Pedestrian Traffic Facts 2019 Data, May 2021.

[2] *Id.,* Table 1 Pedestrian fatalities 2010—4,302, 2019—6,272.

[3] A forward collision warning (FCW) system uses sensors that detect objects in front of vehicles and provides an alert to the driver. An FCW system is able to use the sensors' input to determine the speed of an object in front of it and the distance between the vehicle and the object. If the FCW system determines that the closing distance and velocity between the vehicle and the object is such that a collision may be imminent, the system is designed to induce an immediate forward crash avoidance response by the vehicle operator. FCW systems may detect impending collisions with any number of roadway obstacles, including vehicles and pedestrians. Warning systems in use today provide drivers with a visual warning signal, such as an illuminated telltale on or near the instrument panel, an auditory signal, or a haptic signal that provides tactile feedback to the driver to warn the driver of an impending collision so the driver may intervene. FCW systems alone do not brake the vehicle.

[4] Hereafter, when this final rule refers to ''AEB'' generally, unless the context clearly indicates otherwise, it refers to a system that has: (a) an FCW component to alert the driver to an impending collision with a forward obstacle; (b) a CIB component that automatically applies the vehicle's brakes if the driver does not respond to the FCW; and (c) a DBS component that automatically supplements the driver's brake application if the driver applies insufficient manual braking to avoid a crash. Furthermore, unless the context indicates otherwise, reference to AEB includes both lead vehicle AEB and PAEB.

[5] *https://www.transportation.gov/sites/dot.gov/files/2022-01/USDOT_National_Roadway_Safety_Strategy_0.pdf.*

[6] The Insurance Institute for Highway Safety (IIHS) estimates a 50 percent reduction in front-to-rear crashes of vehicles with AEB (IIHS, 2020) and a 25 to 27 percent reduction in pedestrian crashes for PAEB (IIHS, 2022).

[7] Public Law 117–58, 24208 (Nov. 15, 2021).

[8] 77 FR 39561 (Jul. 2, 2012).

[9] This final rule does not split the terminology of these CIB and DBS functionalities outside of certain contexts, like discussions of NCAP, but instead considers them both as parts of AEB. The final rule includes performance tests that would require an AEB system that has both CIB and DBS functionalities.

[10] 80 FR 68604 (Nov. 5, 2015).

[11] 87 FR 13452 (Mar. 9, 2022). *See https://www.regulations.gov,* docket number NHTSA–2021–0002.

2022. As part of this voluntary commitment, manufacturers are including both FCW and a CIB system that reduces a vehicle's speed in certain rear-end crash-imminent test conditions.

NHTSA also conducted research to understand the capabilities of PAEB systems beginning in 2011. This work began with an assessment of the most common pedestrian crash scenarios to determine how test procedures could be designed to address them. As part of this research, the agency looked closely at a potential pedestrian mannequin to be used during testing and explored several aspects of the mannequin, including size and articulation of the arms and legs. This work resulted in a November 2019 draft research test procedure providing the methods and specifications for collecting performance data on PAEB systems for light vehicles.[12] This procedure was expanded to cover updated vehicle speed ranges and different ambient conditions and included in a March 2022 request for comments notice proposing to include PAEB, higher speed AEB, blind spot warning and blind spot intervention in NCAP.[13]

Need for Regulation

While the above actions have increased market penetration of AEB systems, reduced injuries, and saved lives, NHTSA believes that mandating AEB systems that can address both lead vehicle and pedestrian crashes is appropriate and necessary to better address the safety need. NHTSA incorporated FCW into NCAP beginning in model year 2011 and AEB into NCAP beginning in model year 2018. This has achieved success, with approximately 65% of new vehicles meeting the lead vehicle test procedures included in NCAP.[14] Similarly, the voluntary commitment resulted in approximately 90 percent of new light vehicles manufactured in 2022 having an AEB system.

That said, the test speeds and performance specifications in NCAP and the voluntary commitment do not ensure that the systems perform in a way that will prevent or mitigate crashes resulting in serious injuries and fatalities. The vast majority of fatalities, injuries, and property damage crashes occur at speeds above 40 km/h (25 mph), which are above those covered by the voluntary commitment.

Voluntary measures are intended to supplement rather than substitute for the FMVSSs, which remain NHTSA's core method of ensuring that all motor vehicles can achieve an adequate level of safety performance. The NCAP program is designed to provide valuable safety-related information to consumers in a simple to understand way, but the agency believes that gaps in market penetration will continue to exist for the most highly effective AEB systems. NHTSA has also observed that, in the case of both electronic stability control and rear visibility, only approximately 70 percent of vehicles had these technologies during the time they were part of NCAP. Thus, while NCAP serves a vital safety purpose, only regulation can ensure that all vehicles are equipped with AEB that meet minimum performance requirements.

These considerations are of even greater weight when deciding whether to require a system that can reduce pedestrian crashes, and the agency has concluded that PAEB is both achievable and necessary. Pedestrian fatalities are increasing, and NHTSA's testing reveals that PAEB systems will be able to significantly reduce these deaths.[15] Manufacturers' responses to adding lead vehicle AEB and other technologies to NCAP suggest that it will take several years after PAEB is introduced to NCAP before the market begins to see significant numbers of new vehicles that are able to meet a finalized NCAP test. Even so, since PAEB addresses the safety of someone other than a vehicle occupant, it is not clear if past experience with NCAP is necessarily indicative of how quickly PAEB systems will reach the market penetration levels of lead vehicle AEB.

A final factor weighing in favor of requiring AEB is that the technology is significantly more mature now than it was at the time of the voluntary commitment and when it was introduced into NCAP. NHTSA's most recent testing has shown that higher performance levels than those in the voluntary commitment or the existing NCAP requirements are now practicable. Many model year 2019 and 2020 vehicles were able to repeatedly avoid impacting the lead vehicle in CIB tests and the pedestrian test mannequin in PAEB tests, even at higher test speeds than those prescribed currently in the agency's CIB and PAEB test procedures.

These results show that AEB systems can reduce the frequency and severity of both lead vehicle and pedestrian crashes. Mandating AEB systems would address a clear and, in the case of pedestrian deaths, growing safety problem. To wait for market-driven adoption, even to the extent spurred on by NCAP, would lead to deaths and injuries that could be avoided if the technology were required.

Summary of the NPRM

In view of the significant safety problem and NHTSA's recent test results, and consistent with the Safety Act and BIL, on June 13, 2023 (88 FR 38632) NHTSA published an NPRM proposing a new FMVSS requiring AEB systems that can address both lead vehicle and pedestrian collisions on all new light vehicles. The proposed lead vehicle AEB test procedures built on the existing FCW, CIB, and DBS NCAP procedures, but proposed higher speed performance requirements. Crash avoidance was proposed at speeds up to 100 km/h (62 mph) when manual braking is applied and up to 80 km/h (50 mph) when no manual braking is applied during the test. NHTSA proposed testing under both daylight and darkness lighting conditions, noting the importance of darkness testing of PAEB because more than three-fourths of all pedestrian fatalities occur in conditions other than daylight.

The proposal included four requirements for the AEB system for both lead vehicles and pedestrians. The AEB system would be required to: (1) provide an FCW at any forward speed greater than 10 km/h (6.2 mph), presented via auditory and visual modalities, with permissible additional warning modes, such as haptic; (2) apply the brakes automatically at any forward speed greater than 10 km/h (6.2 mph) when a collision with a lead vehicle or a pedestrian is imminent, including at speeds above those tested by NHTSA; (3) prevent the vehicle from colliding with the lead vehicle or pedestrian test mannequin when tested according to the proposed test procedures, which would include pedestrian tests in both daylight and darkness and two false positive tests; and (4) provide visual notification to the driver of any malfunction that causes the AEB system not to meet the minimum proposed performance requirements.

To ensure test repeatability, NHTSA proposed specifications for the test devices that would be used in both the lead vehicle and pedestrian compliance tests, relying in large part on relevant International Organization for Standardization standards.

[12] 84 FR 64405 (Nov. 21, 2019).

[13] 87 FR 13452 (Mar. 9, 2022).

[14] Percentage based on the vehicle manufacturer's model year 2022 projected sales volume reported through the New Car Assessment Program's annual vehicle information request.

[15] NHTSA's accompanying Final Regulatory Impact Analysis (FRIA) estimates the impacts of this final rule. The FRIA can be found in the docket for this final rule. The docket number is listed in the heading of this document.

NHTSA proposed that all vehicles manufactured four years after the publication date of a final rule would be required to meet all requirements. NHTSA also proposed that all vehicles manufactured on or after three years after the publication date of a final rule would be required to meet all requirements except that lower speed PAEB performance test requirements would not apply. Small-volume manufacturers, final-stage manufacturers, and alterers would be provided an additional year (added to those above) to meet the requirements of the final rule.

NHTSA sought comments on all aspects of the NPRM and any alternative requirements that would address the safety problem. In response, over 1,000 comments were received from a wide variety of stakeholders and interested persons. These comments are available in the docket for the NPRM.[16]

This Final Rule

After careful consideration of all comments, this final rule adopts most of the proposed NPRM requirements, with a few of the changes relevant to significant matters. The differences between the NPRM and the final rule are noted at the end of this Executive Summary and discussed in the relevant sections of this preamble.

With this final rule, NHTSA has issued a Final Regulatory Impact Analysis (FRIA), available in the docket for this final rule (NHTSA–2023–0021).

NHTSA estimates that systems can achieve the requirements of this final rule primarily through upgraded software, with a limited number of vehicles needing additional hardware. Therefore, the incremental cost associated with this rule reflects the cost of a software upgrade that will allow current systems to achieve lead vehicle AEB and PAEB functionality that meets the requirements specified in this rule and the cost to equip a second sensor (radar) on five percent of the estimated fleet that is not projected to have the needed hardware. Taking into account both software and hardware costs, the total annual cost associated with this final rule is approximately $354 million in 2020 dollars.

Table 1 below summarizes the finding of the benefit-cost analysis. The projected benefits of this rule greatly exceed the projected costs. The lifetime monetized net benefit of this rule is projected to be between $5.82 and $7.26 billion with a cost per equivalent life saved of between $550,000 and $680,000, which is far below the Department's recommended value of a statistical life saved, of as $11.6 million in 2020 dollars.

Table 1: Lifetime Summary of Benefits and Costs for Passenger Cars and Light Trucks (Millions 2020$), Discount Rate

Benefits	3% Discount Rate	7% Discount Rate
Lifetime Monetized	$7,610	$6,180
Costs		
Lifetime Monetized	$354	$354
Net Benefits		
Lifetime Monetized	$7,260	$5,820

Table 2: Estimated Quantifiable Benefits

Benefits	
Fatalities Reduced	362
Injuries Reduced	24,321

Table 3: Estimated Installation Costs (2020$)

Category	**Percentage of New Light Vehicle Impacted**	**Total Annual Cost (Millions)**
Software	100%	$282.20
Hardware	5%	$71.86
Total		$354.06

[16] *https://www.regulations.gov/docket/NHTSA-2023-0021/comments.*

Table 4: Estimated Cost Effectiveness

Cost per Equivalent Life Saved	
AEB Systems	$0.55 to $0.68 million*

*The range presented reflects the use of a 3% or 7% discount rate.

Differences Between This Final Rule and the NPRM

NHTSA has made a number of changes to the NPRM based on information from the comments. The changes are discussed below. NHTSA discusses each of these changes in the relevant sections of this preamble.

• In the NPRM, NHTSA estimated that systems can achieve the proposed requirements through upgraded software alone. Commenters suggested that in some instances additional hardware will also be needed, so the incremental cost associated with this rule now includes the cost of a software upgrade and the cost to equip a second sensor (radar) on the five percent of the estimated fleet that does not now have the needed hardware.

• NHTSA has made changes to lead time and compliance date requirements. The NPRM proposed that all vehicles comply with the requirements within 3 years, except for some higher speed PAEB performance requirements in darkness (which had 1 year more to comply than other requirements). This final rule requires that manufacturers comply with all provisions of the rule at the end of a 5-year period starting the first September 1 following publication of this rule, which would be September 1, 2029.[17] The requirements of this final rule compel robust AEB systems that are practicable, but the agency has determined that more time is needed for the technology to mature and be deployed into all vehicles.[18] We expect that many vehicles will be equipped with AEB systems that meet the new rule earlier than September 1, 2029, because of redesign schedules, but that manufacturers will be able to meet the requirement for all new vehicles by the new start date.

• This final rule modifies the range of forward speeds at which the AEB must operate. The NPRM required FCW and AEB systems to operate at any forward speed greater than 10 km/h. This final rule places an upper bound on the requirement that an AEB system operate of 145 km/h (90.1 mph) for FCW and lead vehicle AEB and 73 km/h (45.4 mph) for pedestrian AEB. This final rule also clarifies the environmental conditions under which the AEB system must perform to be the same environmental conditions specified in the track testing.

• This final rule includes an explicit prohibition against manufacturers installing a control designed for the sole purpose of deactivation of the AEB system, except where provided below as it relates to law enforcement. This final rule also allows for controls that have the ancillary effect of deactivating the AEB system. For instance, a manufacturer may choose to deactivate AEB if the driver has activated ''tow mode'' and the manufacturer has determined that AEB cannot perform safely while towing a trailer.

• This final rule modifies the FCW visual signal location requirement to increase the specified maximum visual angle from 10 degrees to 18 degrees in the vertical direction. This change from the NPRM provides manufacturers with the flexibility to locate the visual warning signal within the typical area of the upper half of the instrument panel and closer to the central field of view of the driver. While the agency continues to believe that an FCW visual warning signal presented near the central forward-looking region is ideal, it does not consider a head-up display to be necessary for the presentation of the FCW visual signal that is part of a complete AEB system.

• The rule contains several additional minor changes as well. These include the following:

—In the obstructed pedestrian scenario in PAEB performance tests, the NPRM did not specify the distance between the pedestrian test dummy and the farthest obstructing vehicle. This final rule corrects this oversight.

—In the false activation tests, this final rule adjusts the regulatory text to clarify that testing for false activation is done with and without manual brake application.

—Some minor parameters and definitions were modified, and various definitions were added, to clarify details of the lead vehicle and PAEB test procedures.

—To increase practicability of running the tests, a third manual brake application controller option, a force only feedback controller, was added. The force feedback controller is substantially similar to the hybrid controller with the commanded brake pedal position omitted, leaving only the commanded brake pedal force application.

—The procedure in Annex C, section C.3 of ISO 19206–2:2018 is specific for pedestrian targets, but recent testing performed by the agency indicates that the three-position measurement specified in Annex C, section C.3 of ISO 19206–3:2021 provides more reduction in multi-path reflections and offers more accurate radar cross section values. The agency is incorporating by reference ISO 19206–3:2021.

II. Background

A. The Safety Problem

There were 38,824 fatalities in motor vehicle crashes on U.S. roadways in 2020 and early estimates put the number of fatalities at 42,795 for 2022.[19] This is the highest number of fatalities since 2005. While the upward trend in fatalities may be related to increases in risky driving behaviors during the COVID–19 pandemic,[20] agency data show an increase of 3,356 fatalities between 2010 and 2019.[21] Motor vehicle crashes have also trended upwards since 2010, which corresponds to an increase in fatalities, injuries, and property damage.

[17] As proposed in the NPRM, this final rule provides small-volume manufacturers, final stage manufacturers, and alterers an additional year of lead time. As a result of the changes to the proposed lead time and compliance date requirements, small-volume manufactures, final stage manufactures, and alterers would be required to comply with all provisions of the rule starting September 1, 2030.

[18] As part of this extension of the lead time, the agency has removed the graduated approach to the PAEB performance requirements. The NPRM proposed that most PAEB requirements be met 3 years after a final rule, with an additional year for the dark lighting condition requirement. With the 5-year lead time for all requirements, there is no need for the phasing-in of requirements, so the agency is not adopting it.

[19] *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813266, https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813428.*

[20] These behaviors relate to increases in impaired driving, the non-use of seat belts, and speeding. NHTSA also cited external studies from telematics providers that suggested increased rates of cell phone manipulation during driving in the early part of the pandemic.

[21] NHTSA's Traffic Safety Facts Annual Report, Table 2, *https://cdan.nhtsa.gov/tsftables/tsfar.htm#Accessed* March 28, 2023.

Overall Rear-End Crash Problem

NHTSA uses data from the Fatality Analysis Reporting System (FARS) and the Crash Report Sampling System (CRSS) to account for and understand motor vehicle crashes. As defined in a NHTSA technical manual relating to data entry for FARS and CRSS, rear-end crashes are incidents where the first event is defined as the frontal area of one vehicle striking a vehicle ahead in the same travel lane. In a rear-end crash, as instructed by the 2020 FARS/CRSS Coding and Validation Manual, the vehicle ahead is categorized as intending to head either straight, left or right, and is either stopped, travelling at a lower speed, or decelerating.[22]

In 2019, rear-end crashes accounted for 32.5 percent of all crashes, making them the most prevalent type of crash.[23] Fatal rear-end crashes increased from 1,692 in 2010 to 2,363 in 2019 and accounted for 7.1 percent of all fatal crashes in 2019, up from 5.6 percent in 2010. Because data from 2020 and 2021 may not be representative of the general safety problem due to the COVID–19 pandemic, and data from 2022 are not yet available, the following discussion refers to data from 2010 to 2020 when discussing rear-end crash safety problem trends, and 2019 data when discussing specific characteristics of the rear-end crash safety problem. While injury and property-damage-only rear-end crashes from 2010 (476,000 and 1,267,000, respectively) and 2019 (595,000 and 1,597,000, respectively) are not directly comparable due to differences in database structure and sampling, the data indicate that these numbers have not significantly changed from 2010–2015 (NASS–GES sampling) and 2016–2019 (CRSS sampling).

BILLING CODE 4910–59–P

Table 5: 2010-2020 Rear-end crashes All Vehicle Types By Crash Severity[24]

First Harmful Event	Rear-End Crash Severity			
	Fatal	Injury	Property-Damage-Only	Total Rear-End
	Number	Number	Number	Number
2010	1,692	476,000	1,267,000	1,745,000
2011	1,808	475,000	1,245,000	1,721,000
2012	1,836	518,000	1,327,000	1,847,000
2013	1,815	503,000	1,326,000	1,831,000
2014	1,971	522,000	1,442,000	1,966,000
2015	2,225	556,000	1,543,000	2,101,000
2016	2,372	661,000	1,523,000	2,187,000
2017	2,473	615,000	1,514,000	2,132,000
2018	2,459	594,000	1,579,000	2,175,000
2019	2,363	595,000	1,597,000	2,194,000
2020	2,428	417,000	1,038,000	1,457,000

The table below presents a breakdown of all the crashes in 2019 by the first harmful event where rear-end crashes represent 7.1 percent of the fatal crashes, 31.1 percent of injury crashes and 33.2 percent (or the largest percent) of property-damage-only crashes.

[22] *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813251* Category II Configuration D. Rear-End.

[23] *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813141* Traffic Safety Facts 2019, Table 29.

[24] Compiled from NHTSA's Traffic Safety Facts Annual Report, Table 29 from 2010 to 2020, *https://cdan.nhtsa.gov/tsftables/tsfar.htm#Accessed* March 28, 2023.

Table 6: 2019 Crashes, by First Harmful Event, Manner of Collision, and Crash Severity[25]

First Harmful Event	Crash Severity					
	Fatal		Injury		Property-Damage-Only	
	Number	Percent	Number	Percent	Number	Percent
Collision with Motor Vehicle in Transport:						
Angle	6,087	18.2	531,000	27.7	956,000	19.9
Rear-end	2,363	7.1	595,000	31.1	1,597,000	33.2
Sideswipe	917	2.7	138,000	7.2	739,000	15.4
Head On	3,639	10.9	91,000	4.7	86,000	1.8
Other / Unknown	150	0.4	8,000	0.4	69,000	1.4
Collision with a Fixed Object:						
	9,579	28.6	281,000	14.7	657,000	13.7
Collision with Object Not Fixed:						
	7,826	23.4	214,000	11.2	648,000	13.5
Non-collision:						
	2,870	8.6	58,000	3.0	54,000	1.1

The following paragraphs provide a breakdown of rear-end crashes by vehicle type, posted speed limit, light conditions and atmospheric conditions for the year 2019 based on NHTSA's FARS, CRSS, and the 2019 Traffic Safety Facts sheets.

Rear-End Crashes by Vehicle Type

In 2019, passenger cars and light trucks were involved in the vast majority of rear-end crashes. NHTSA's ''Manual on Classification of Motor Vehicle Traffic Accidents'' provides a standardized method for crash reporting. It defines passenger cars as ''motor vehicles used primarily for carrying passengers, including convertibles, sedans, and station wagons,'' and light trucks as ''trucks of 10,000 pounds gross vehicle weight rating or less, including pickups, vans, truck-based station wagons, and utility vehicles.'' [26] The 2019 data show that crashes where a passenger car or light truck is a striking vehicle represent at least 70 percent of fatal rear-end crashes, 95 percent of crashes resulting in injury, and 96 percent of damage only.[27]

[25] NHTSA's Traffic Safety Facts Annual Report, Table 29 for 2019, *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813141* Accessed March 29, 2024.

[26] *https://www-fars.nhtsa.dot.gov/help/terms.aspx.*

[27] NHTSA's Traffic Safety Facts Annual Report, 2019, *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813141.*

Table 7: Rear-End Crashes with Impact Location - Front, by Vehicle Type, in 2019[28]

Vehicle Body Type, Initial Impact-Front	Fatal	Injury	Property-Damage-Only
Passenger Car	888	329,000	906,000
Light Truck	910	245,000	642,000
All Other	762	31,000	57,000

Rear-End Crashes by Posted Speed Limit

When looking at posted speed limit and rear-end crashes, data show that the majority of the crashes happened in areas where the posted speed limit was 60 mph (97 km/h) or less. The table below shows the rear-end crash data by posted speed limit and vehicle type from 2019. About 60 percent of fatal crashes were on roads with a speed limit of 60 mph (97 km/h) or lower. That number is 73 percent for injury crashes and 78 percent for property-damage-only crashes.

Table 8: 2019 Rear-end Crashes Involving Passenger Cars, MPVs, and Light Trucks with Frontal Impact by Posted Speed Limit[29, 30]

Vehicles by Posted speed limit	Passenger Cars, Light trucks, by Crash Severity					
	Fatal		Injury		Property-Damage-Only	
	Number	Percent	Number	Percent	Number	Percent
25 mph or less	16	1%	28,000	5%	103,000	7%
30	30	2%	24,000	4%	78,000	5%
35	95	5%	91,000	16%	267,000	17%
40	87	5%	66,000	11%	175,000	11%
45	223	12%	129,000	22%	373,000	24%
50	99	6%	19,000	3%	58,000	4%
55	401	22%	55,000	10%	122,000	8%
60	133	7%	12,000	2%	31,000	2%
65 and above	684	38%	75,000	13%	153,000	10%
All other	30	2%	75,000	13%	187,000	12%
Total:	1,798	100%	574,000	100%	1,547,000	100%

Rear-End Crashes by Light Condition

Slightly more fatal rear-end crashes (51 percent) occurred during daylight than during dark-lighted and dark-not-lighted conditions combined (43 percent) in 2019. Injury and property-damage-only rear-end crashes were reported to have happened overwhelmingly during daylight, at 76 percent for injury rear-end crashes and 80 percent for property-damage-only rear-end crashes. The table below presents a summary of all 2019 rear-end crashes of light vehicles by light conditions, where the impact location is the front of a light vehicle.

[28] Generated from FARS and CRSS databases (*https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/FARS/2019/National/, https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CRSS/2019/*, accessed October 17, 2022).

[29] Generated from FARS and CRSS databases (*https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/FARS/2019/National/, https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CRSS/2019/*, accessed October 17, 2022).

[30] Total percentages may not equal the sum of individual components due to independent rounding throughout the Safety Problem section.

Table 9: 2019 Rear-end Crashes with Light Vehicle Front Impact, by Light Condition[31]

Light Condition	Crash severity					
	Fatal		Injury		Property-Damage-Only	
	Number	Percent	Number	Percent	Number	Percent
Daylight	925	51%	436,000	76%	1,232,000	80%
Dark - Not Lighted	438	24%	28,000	5%	59,00060,767	4%
Dark - Lighted	349	19%	86,000	15%	192,000	12%
All Other	86	5%	24,000	4%	65,000	4%
Total	1,798	100%	574,000	100%	1,547,000	100%

Rear-End Crashes by Atmospheric Conditions

In 2019, the majority of rear-end crashes of light vehicles were reported to occur during clear skies with no adverse atmospheric conditions. These conditions were present for 72 percent of all fatal rear-end crashes, while 14 percent of fatal rear-end crashes were reported to occur during cloudy conditions. Similar trends are reported for injury and property-damage-only crashes. A summary of 2019 rear-end crashes of light vehicle with frontal impact by atmospheric conditions is presented in the table below.

Table 10: 2019 Rear-End Crashes Involving Light Vehicles with Frontal Impact, by Atmospheric Conditions[32]

Crashes Atmospheric Conditions	Crash Severity					
	Fatal		Injury		Property-Damage-Only	
	Number	Percent	Number	Percent	Number	Percent
Clear, No Adverse	1,295	72%	426,000	74%	1,113,000	72%
Cloudy	247	14%	87,000	15%	245,000	16%
All Other	256	14%	61,000	11%	189,000	12%
Total	1,798	100%	574,000	100%	1,547,000	100%

Pedestrian Fatalities and Injuries

While the number of fatalities from motor vehicle traffic crashes is increasing, pedestrian fatalities are increasing at a greater rate than the general trend and becoming a larger percentage of total fatalities. In 2010, there were 4,302 pedestrian fatalities (13 percent of all fatalities), which increased to 6,272 (17 percent of all fatalities) in 2019. The latest agency estimation data indicate that there were 7,345 pedestrian fatalities in 2022.[33] Since data from 2020 and 2021 may not be representative of the general safety problem due to the COVID–19 pandemic and data for 2022 are early estimates, the following sections refer to data from 2010 to 2020 when discussing pedestrian safety problem trends, and 2019 data when discussing specific characteristics of the pedestrian safety problem. While the number of pedestrian fatalities is increasing, the number of pedestrians injured in crashes from 2010 to 2020 has not changed significantly, with exception of the 2020 pandemic year. As shown in the table below, the number and percentage of pedestrian fatalities and injuries for the 2010 to 2020 period is presented in relationship to the total number of fatalities and total number of people injured in all crashes.

[31] Generated from FARS and CRSS databases (*https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/FARS/2019/National/, https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CRSS/2019/,* accessed October 17, 2022).

[32] Generated from FARS and CRSS databases (*https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/FARS/2019/National/, https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CRSS/2019/,* accessed October 17, 2022).

[33] *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813448.*

Table 11: 2010-2020 Traffic Crash Fatalities and Pedestrian Fatalities, and Injured People and Pedestrians Injured[34]

Year	Total Fatalities[1]	Pedestrian Fatalities[1]		Total People Injured[2]	Pedestrian Injured[2]	
		Number	Percent of Total Fatalities		Number	Percent of Total Injured
2010	32,999	4,302	13%	2,248,000	70,000	3%
2011	32,479	4,457	14%	2,227,000	69,000	3%
2012	33,782	4,818	14%	2,369,000	76,000	3%
2013	32,893	4,779	15%	2,319,000	66,000	3%
2014	32,744	4,910	15%	2,343,000	65,000	3%
2015	35,484	5,494	15%	2,455,000	70,000	3%
2016	37,806	6,080	16%	3,062,000	86,000	3%
2017	37,473	6,075	16%	2,745,000	71,000	3%
2018	36,835	6,374	17%	2,710,000	75,000	3%
2019	36,355	6,272	17%	2,740,000	76,000	3%
2020	38,824	6,516	17%	2,282,015	55,000	2%

[1] Data source: FARS 2010–2019, 2020 Annual Report (ARF)

[2] Data source: NASS GES 2010–2015, CRSS 2016–2019

The following sections present a breakdown of pedestrian fatalities and injuries by initial impact point, vehicle type, posted speed limit, lighting condition, and pedestrian age for the year 2019.

Pedestrian Fatalities and Injuries by Initial Point of Impact and Vehicle Type

In 2019, the majority of pedestrian fatalities, 4,638 (74 percent of all pedestrian fatalities), and injuries, 52,886 (70 percent of all pedestrian injuries), were in crashes where the initial point of impact on the vehicle was the front. When the crashes are broken down by vehicle body type, the majority of pedestrian fatalities and injuries occur where the initial point of impact was the front of a light vehicle (4,069 pedestrian fatalities and 50,831 pedestrian injuries) (see the table below).[35]

Table 12: 2019 Pedestrian Fatalities and Injuries, by Initial Point of Impact Front and Vehicle Body Type[36]

Vehicle Body Type, Initial Impact - Front	Crash Severity			
	Pedestrian Fatalities		Pedestrian Injuries	
	Number	Percent	Number	Percent
Passenger Car	1,976	43%	30,968	59%
Light Truck	2,093	45%	19,863	38%
All Other	569	12%	2,055	4%
Total	4,638	100%	52,886	100%

Pedestrian Fatalities and Injuries by Posted Speed Limit Involving Light Vehicles

In 2019, the majority of pedestrian fatalities from crashes involving light vehicles with the initial point of impact as the front occurred on roads where the posted speed limit was 45 mph or less, (about 70 percent). There is a near even split between the number of pedestrian fatalities in 40 mph and lower speed zones and in 45 mph and above speed zones (50 percent and 47 percent respectively with the remaining unknown or not reported). As for pedestrian injuries, in 34 percent of the sampled data, the posted speed limit is either not reported or unknown. In

[34] *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813079* Pedestrian Traffic Facts 2019 Data, May 2021, *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813310* Pedestrian Traffic Facts 2020, Data May 2022.

[35] As described previously, passenger cars and light trucks are the representative population for vehicles with a gross vehicle weight rating (GVWR) of 4,536 kg (10,000 lbs.) or less.

[36] NHTSA's Traffic Safety Facts Annual Report, Table 99 for 2019, *https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/813141* Accessed March 29, 2024.

2019, 57 percent of the pedestrians were injured when the posted speed limit was 40 mph or below, and 9 percent when the posted speed limit was above 40 mph with the remaining not reported, reported as unknown, or reported as no speed limit. The table below shows the number of pedestrian fatalities and injuries for each posted speed limit.

Table 13: 2019 Pedestrian Fatalities and Injuries Involving Light Vehicles, by Posted Speed Limit and Initial Point of Impact Front[37]

Posted speed limit	Crash Severity			
	Pedestrian Fatalities		Pedestrian Injuries	
	Number	Percent	Number	Percent
5 mph	3	0.07%	185	0.36%
10 mph	7	0.17%	287	0.56%
15 mph	10	0.25%	865	1.70%
20 mph	14	0.34%	479	0.94%
25 mph	346	8.50%	9,425	18.54%
30 mph	325	7.99%	4,254	8.37%
35 mph	765	18.80%	9,802	19.28%
40 mph	551	13.54%	3,703	7.28%
45 mph	821	20.18%	3,094	6.09%
50 mph	177	4.35%	302	0.59%
55 mph	463	11.38%	546	1.07%
60 mph	105	2.58%	130	0.26%
65 mph	199	4.89%	241	0.47%
70 mph	103	2.53%	105	0.21%
75 mph	19	0.47%	4	0.01%
80 mph	2	0.05%	25	0.05%
Not Reported	118	2.90%	15,017	29.54%
Unknown	16	0.39%	176	0.35%
No Statutory Limit / Non-Trafficway Area	25	0.61%	2,191	4.31%
Total	4,069	100%	50,831	100%

Pedestrian Fatalities and Injuries by Lighting Condition Involving Light Vehicles

The majority of pedestrian fatalities where the front of a light vehicle strikes a pedestrian occurred in dark lighting conditions, 3,131 (75 percent). There were 20,645 pedestrian injuries (40 percent) in dark lighting conditions and 27,603 pedestrian injuries (54 percent) in daylight conditions.

[37] The accompanying FRIA estimates the impacts of the rule based on the estimated travel speed of the striking vehicle. This table presents the speed limit of the roads on which pedestrian crashes occur.

Table 14: 2019 Pedestrian Fatalities and Injuries Involving Light Vehicles, by Lighting Condition and Initial Point of Impact Front[38]

Light Condition	Crash Severity			
	Pedestrian Fatalities		Pedestrian Injuries	
	Number	Percent	Number	Percent
Daylight	767	19%	27,603	54%
Dark–Not Lighted	1,464	36%	4,551	9%
Dark–Lighted	1,621	40%	15,996	31%
Dark–Unknown Light	46	1%	98	0%
All Other	171	4%	2,583	5%
Total	4,069	100%	50,831	100%

Pedestrian Fatalities and Injuries by Age Involving Light Vehicles

In 2019, 646 fatalities and approximately 106,600 injuries involved children aged 9 and below. Of these, 68 fatalities and approximately 2,700 injuries involved pedestrians aged 9 and below in crashes with the front of a light vehicle. As shown in the table below, the first two age groups (under age 5 and ages 5 to 9) each represent less than 1 percent of the total pedestrian fatalities in crashes with the front of a light vehicle. These age groups also represent about 1.5 and 3.8 percent of the total pedestrian injuries in crashes with the front of a light vehicle, respectively. In contrast, age groups between age 25 and 69 each represent approximately 7 percent of the total pedestrian fatalities in crashes with the front of a light vehicle, with the 55 to 59 age group having the highest percentage at 10.9 percent. Pedestrian injury percentages were less consistent, but distributed similarly, to pedestrian fatalities, with lower percentages reflected in children aged 9 and below and adults over age 70.

[38] Generated from FARS and CRSS databases (*https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/FARS/2019/National/*, *https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CRSS/2019/*, accessed October 17, 2022).

Table 15: 2019 Pedestrians Fatalities and Injuries in Traffic Crashes Involving Light Vehicles by Initial Point of Impact Front[39] and Age Group[40]

Age Group	United States Population (thousand)	Percent of Population	Pedestrian Fatalities		Pedestrians Injuries	
			Light Vehicle Front-Impact Ped. Fatalities	Percent of Total Pedestrian Fatalities in Light Vehicle Front-Impact Crashes	Light Vehicle Front-Impact Ped. Injuries	Percent of Total Pedestrian Injuries in Light Vehicle Front-Impact Crashes
<5	19,736	6.1%	37	0.9%	770	1.5%
5-9	20,212	6.2%	31	0.8%	1,907	3.8%
10-14	20,827	6.4%	58	1.4%	2,830	5.6%
15-20	20,849	6.4%	159	3.9%	5,673	11.2%
21-24	21,254	6.6%	173	4.3%	3,190	6.3%
25-29	23,277	7.2%	287	7.1%	4,394	8.6%
30-34	21,932	6.8%	315	7.7%	3,735	7.3%
35-39	21,443	6.6%	316	7.8%	3,636	7.2%
40-44	19,584	6.0%	277	6.8%	2,812	5.5%
45-49	20,345	6.3%	294	7.2%	2,745	5.4%
50-54	20,355	6.3%	350	8.6%	3,311	6.5%
55-59	21,163	6.5%	442	10.9%	3,678	7.2%
60-64	20,592	6.3%	379	9.3%	3,469	6.8%
65-69	17,356	5.4%	303	7.4%	2,594	5.1%
70-74	14,131	4.4%	207	5.1%	1,724	3.4%
75-79	9,357	2.9%	172	4.2%	1,136	2.2%
80+	11,943	3.7%	252	6.2%	1,127	2.2%
Unknown			17	0.4%	2,103	4.1%
Total			4,069	100%	50,831	100%

BILLING CODE 4910–59–C

B. Bipartisan Infrastructure Law (BIL)

This final rule responds to Congress's directive that NHTSA require AEB on all passenger vehicles. On November 15, 2021, the President signed the Bipartisan Infrastructure Law, codified as the Infrastructure Investment and Jobs Act (Pub. L. 117–58). Section 24208(a) of BIL added 49 U.S.C. 30129, directing the Secretary of Transportation to promulgate a rule to establish minimum performance standards with respect to crash avoidance technology and to require that all passenger motor vehicles manufactured for sale in the United States be equipped with a forward collision warning (FCW) system and an automatic emergency braking system. The FCW and AEB system is required to alert the driver if the vehicle is closing its distance too quickly to a vehicle ahead or to an object in the path of travel ahead and a collision is imminent, and to automatically apply

[39] Generated from FARS and CRSS databases (*https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/FARS/2019/National/, https://www.nhtsa.gov/file-downloads?p=nhtsa/downloads/CRSS/2019/,* accessed October 17, 2022).

[40] *https://www.census.gov/data/tables/2019/demo/age-and-sex/2019-age-sex-composition.html,* Table 12.

the brakes if the driver fails to do so. This final rule responds to this mandate and is estimated to reduce the frequency and severity of vehicle-to-vehicle rear-end crashes and to reduce the frequency and severity of vehicle crashes into pedestrians.

BIL requires that ''all passenger motor vehicles'' manufactured for sale in the United States be equipped with AEB and FCW. The BIL term ''passenger motor vehicle'' encompasses more vehicle categories than the term ''passenger car'' that NHTSA defines in 49 CFR 571.3. Thus, including multipurpose passenger vehicles, trucks, and buses aligns with Congress's mandate. Additionally, NHTSA considers passenger cars, truck, buses, and multipurpose passenger vehicles as light vehicles and generally uses the 10,000 GVWR cut-off for FMVSS that apply to light vehicles.[41] As a result, in this final rule, NHTSA requires AEB and FCW on all passenger cars and multipurpose passenger vehicles, trucks, and buses with a gross vehicle weight rating (GVWR) of 10,000 lbs. or less.

BIL further requires that an FCW system alert the driver if there is a ''vehicle ahead or an object in the path of travel'' if a collision is imminent.

NHTSA interprets BIL as requiring AEB capable of detecting and responding to vehicles and objects and authorizing NHTSA to promulgate specific performance requirements. NHTSA's rule requires light vehicles to be equipped with FCW and automatic emergency braking (AEB), and the proposal defines AEB as a system that detects an imminent collision with vehicles, objects, and road users,[42] in or near the path of a vehicle and automatically controls the vehicle's service brakes to avoid or mitigate the collision.

As discussed in the NPRM, section 24208 of BIL does not limit NHTSA's broad authority to issue motor vehicle safety regulations under the Safety Act. NHTSA interprets BIL as a mandate to act on a particular vehicle safety issue and as complementary to NHTSA's authority under the Safety Act. Thus, pursuant to its authority under 49 U.S.C 30111, NHTSA is requiring all light passenger vehicles to be equipped with PAEB in addition to AEB. NHTSA is ensuring that PAEB is available on all light passenger vehicles to address a significant safety problem, and in so doing, recognizes the availability of technology capable of preventing needless injuries and lost lives.

C. High-level Summary of Comments on the NPRM

NHTSA received more than a thousand comments on the proposed rule. The agency received comments from a wide variety of commenters including advocacy groups, manufacturers, trade associations, suppliers, and individuals. The advocacy groups submitting comments included AAA Inc. (AAA), AARP, Advocates for Highway and Auto Safety (Advocates), America Walks, American Foundation for the Blind (AFB), Association of Pedestrian and Bicycle Professionals (APBP), Center for Auto Safety (CAS), Consumer Reports, DRIVE SMART Virginia, Insurance Institute for Highway Safety (IIHS), International Association of Fire Chiefs, Intelligent Transportation Society of America (ITS America), League of American Bicyclists (League), McHenry County Bicycle Advocates, National Safety Council (NSC), Paralyzed Veterans of America (PVA), United Spinal Association, Utah Public Lands Alliance, and Vulnerable Road Users Safety Consortium (VRUSC). Trade associations submitting comments included Alliance for Automotive Innovation (Alliance), American Chemistry Council, American Motorcyclist Association (AMA), Automotive Safety Council (ASC), Autonomous Vehicle Industry Association (AVIA), the Governors Highway Safety Association (GHSA), Lidar Coalition, the Motor and Equipment Manufacturers Association (MEMA), National Automotive Dealers Association (NADA), National Association of City Transportation Officials (NACTO), Association for the Work Truck Industry (NTEA), SAE International (SAE), and Specialty Equipment Market Association (SEMA). We also received comments from individual vehicle manufacturers such as FCA US LLC (FCA), Ford Motor Company (Ford), General Motors LLC (GM), American Honda Motor, Co., Inc. (Honda), Hyundai Motor Company (Hyundai), Mitsubishi Motors R & D of America, Inc. (Mitsubishi), Nissan North America, Inc. (Nissan), Porsche Cars North America (Porsche), Rivian Automotive, LLC (Rivian), Toyota Motor North America, Inc. (Toyota), and Volkswagen Group of America (Volkswagen). Suppliers and developers commenting on the NPRM included Adasky North America (Adasky), Applied Intuition (Applied), Aptiv, Automotive Electronics Products COMPAL Electronics, Inc. (COMPAL), Autotalks, Forensic Rock, LLC (Forensic Rock), Humanetics Safety (Humanetics), Hyundai America Technical Center, Inc. (HATCI), Hyundai MOBIS, imagery Inc. (Imagery), LHP Inc. (LHP), Luminar Technologies, Inc. (Luminar), Mobileye Vision Technologies LTD (Mobileye), Owl Autonomous Imaging, Inc. (Owl AI), Radian Labs LLC (Radian), Robert Bosch LLC (Bosch), Teledyne FLIR (Teledyne), ZF North America (ZF), and Zoox, Inc. (Zoox). Government agencies that commented included the National Transportation Safety Board (NTSB), the City of Houston (Houston), City of Philadelphia (Philadelphia), Humboldt County Association of Governments, Maryland Department of Transportation Motor Vehicle Administration (MDOT), Multnomah County, and Nashville Department of Transportation and Multimodal Infrastructure (Nashville). Healthcare and insurance companies submitting comments included American Property Casualty Insurance Association (APCIA), National Association of Mutual Insurance Companies, and Richmond Ambulance Authority. The agency also received approximately 970 comments from individual commenters. In general, the commenters expressed support for the goals of this rulemaking, and many commenters offered recommendations on the most appropriate way to achieve those goals.

Many commenters shared their general support for requiring AEB as standard equipment on passenger vehicles, while others opposed finalizing the proposed rule for various technical and policy reasons. In general, safety advocates supported finalizing the rule, while vehicle manufacturers opposed various aspects of the proposal, even if they expressed general support for AEB technology. The agency received comments on many aspects of the rule, including comments on the application, the performance requirements, the test procedure conditions and parameters, and the proposed lead time and phase-in schedule.

Consumer advocacy groups primarily supported the rule, with concerns regarding manual deactivation and the proposed requirements regarding PAEB. They urged that any conditions for AEB deactivation be restricted and have data supporting deactivation and asserted that any manual deactivation would need to have multiple steps and require the vehicle to be stationary. Many suggested that the testing speeds be increased to cover a larger portion of the safety problem. Another concern raised

[41] *See,* for example, 49 CFR 571.138, 571.208, and 571.111.

[42] While AEB is defined as a system that detects imminent collision with vehicles, objects, and road users, the performance requirements focus on protecting pedestrians until NHTSA can develop additional research to support a proposal to expand the performance requirements.

by advocacy groups was the lack of test procedures covering bicyclists and users of mobility devices and wheelchairs. They recommended that the agency add more PAEB testing scenarios, noting that there is a significant safety risk for pedestrians and all vulnerable road users. In general, advocacy groups supported the full collision avoidance, no-contact requirement for all proposed AEB tests as a necessity to uphold the strength of the rule.

While vehicle manufacturers supported the installation of AEB, the most significant concerns focused on the stringency of the requirements. The NPRM proposed the AEB system be operational at any forward speed above 10 km/h (6.2 mph). Several vehicle manufacturers and the Alliance opposed the open-ended upper bound, stating it was impracticable or that it would lead to false activations. These commenters stated that the lack of a defined maximum operational speed could create implementation ambiguity and difficulty complying with the rule due to significant development costs. The NPRM further proposed full collision avoidance with the lead vehicle during AEB testing (a no-contact performance requirement). The Alliance, and multiple manufacturers expressing support for the Alliance' comments, stated that a no-contact performance requirement is not practicable and increases the potential for unintended consequences such as inducing unstable vehicle dynamics, removing the driver's authority, increasing false activations, and creating conditions that limit bringing new products to market. These commenters asserted that a lack of rigorous testing by the agency leaves questions as to actual vehicle performance in the field.

The vehicle manufacturers also commented on the feasibility of specific performance requirements under the proposed phase-in schedule, arguing that the agency was mistaken to assume in the NPRM that most vehicles have the necessary hardware to implement this rule. They commented that the proposed phase-in schedule may require redesigns to their systems outside of the normal product development cycle and contended that such a scenario would significantly increase the costs and burdens of compliance. The manufacturers requested that the agency delay the rule by as much as eight years to afford them time to redesign their systems in conjunction with the normal vehicle redesign schedule.

Manufacturers and suppliers generally opposed the agency's proposal to prohibit manual deactivation of the AEB system above 10km/h. Commenters stated the need for deactivation during various scenarios, including four-wheel drive operation, towing, off-road use, car washes and low traction driving. There were multiple suggestions to adopt the deactivation criteria of the United Nations Economic Commission for Europe (UNECE) Regulation No. 152, in place of the NPRM proposed criteria, and to align with UNECE Regulation No. 152 more generally.

Among suppliers and developers, there was not a consensus on the no-contact requirement. Commenters such as Adasky and Luminar expressed support for the no-contact requirement, stating that current technology is capable of this performance. ZF, Aptiv, and Hyundai MOBIS believed the proposed no-contact requirement was not practicable and suggested harmonization with UNECE Regulation No. 152. Generally, those opposed to the no-contact requirement supported hybrid or speed reduction approaches.[43]

ZF, HATCI, and Aptiv supported the ability to manually deactivate the AEB system and recommended harmonization with UNECE Regulation No. 152 deactivation criteria. Imagry opposed the entirety of the NPRM as drawing resources and development away from fully autonomous driving, while Autotalks supported the regulation as ''urgently needed.''

Finally, most individual commenters expressed general support to the goals of this rule, citing the vulnerability of pedestrians on or near roadways. A significant portion of these commenters also noted that children, people with dark skin tones, and those using a wheelchair or mobility device are particularly vulnerable. Individual commenters opposed to this rule cited concerns about off-road operation and false activation.

D. Summary of the Notice of Proposed Rulemaking

NHTSA published the NPRM for this final rule on June 2, 2023 (88 FR 38632). Because this final rule adopts almost all of the requirements proposed in the NPRM, this summary is brief and mirrors the description of the final rule provided in the Executive Summary, *supra.*

1. The NPRM proposed creating a new FMVSS to require AEB systems on light vehicles that can reduce the frequency and severity of both rear-end and pedestrian crashes. The proposed AEB performance requirements were intended to ensure that an AEB system is able to automatically and completely avoid collision with the rear of another vehicle or a pedestrian in specific combinations of scenarios and speeds, while continuing to alert and apply the brakes at speeds beyond those in the test procedure.

2. The NPRM proposed four requirements for the AEB systems. The proposed AEB system must: (a) provide the driver with a forward collision warning (FCW) at any forward speed greater than 10 km/h (6.2 mph); (b) automatically apply the brakes at any forward speed greater than 10 km/h (6.2 mph) when a collision with a lead vehicle or a pedestrian is imminent; (c) prevent the vehicle from contacting the lead vehicle (*i.e.,* vehicle test device) or pedestrian test device when tested according to the proposed test procedures; and (d) detect AEB system malfunctions and notify the driver of any malfunction that causes the AEB system not to meet the proposed minimum performance requirements of the safety standard.

3. The NPRM's test procedures evaluate the lead vehicle AEB performance, PAEB performance, and two scenarios that evaluate situations where braking is not warranted (*i.e.,* false positives). Under this proposed requirement, crash avoidance braking is considered to have occurred when the automatic portion of the brake activation (excluding any manual braking) exceeds 0.25g.

4. For the lead vehicle AEB performance, the agency proposed three test scenarios: lead vehicle stopped, lead vehicle decelerating, and lead vehicle slower-moving. Each lead vehicle scenario is tested at specific speeds or within specified ranges of speeds to evaluate the AEB performance with and without applying manual braking to the subject vehicle.

For the lead vehicle stopped scenario, the agency proposed that the subject vehicle must perform when no manual braking is used at speeds ranging from 10 km/h to 80 km/h, and from 70 km/h to 100 km/h when manual braking is used. The subject (and lead vehicle) speeds proposed for the decelerating lead vehicle scenario were 50 km/h and 80 km/h while the proposed range of lead vehicle deceleration was 0.3 g to 0.5 g. Additionally, for the decelerating lead vehicle scenario, the agency proposed a headway range of 12 m to 40 m for each of the two subject vehicle speeds. For the slower-moving lead vehicle scenario, a subject vehicle must perform at speeds ranging from 40 km/h to 80 km/h when no manual braking

[43] A kind of hybrid approach would maintain no-contact requirements for lower-mid-range speeds while permitting contact at higher speed if acceptable speed reductions that reduce the risk of serious injury can be achieved in the higher-speed scenarios.

is used, while a subject vehicle must perform at speeds ranging from 70 km/h to 100 km/h when manual braking is used.

5. For the assessment of PAEB performance, the proposed test procedures evaluate the subject vehicle in three pre-crash scenarios involving pedestrians: (a) where the pedestrian crosses the road in front of the subject vehicle, (b) where the pedestrian walks alongside the road in the path of the subject vehicle, and (c) where the pedestrian stands in the roadway in front of the subject vehicle. The NPRM proposed a specified range of speeds in both daylight and darkness lighting conditions with lower and upper beam headlamps activated.

6. NHTSA proposed that AEB systems continuously detect system malfunctions. If an AEB system detects a malfunction that prevents it from performing its required safety function, the vehicle would provide the vehicle operator with a warning. The warning would be required to remain active as long as the malfunction exists while the vehicle's starting system is on. NHTSA considers a malfunction to include any condition in which the AEB system fails to meet the proposed performance requirements. NHTSA proposed that the driver be warned in all instances of component or system failures, sensor obstructions, environmental limitations (like heavy precipitation), or other situations that would prevent a vehicle from meeting the proposed AEB performance requirements.

7. With respect to compliance dates, the NPRM proposed that vehicles manufactured on or after September 1, three years after the publication date of a final rule, but before September 1, four years after the publication date of a final rule, would be required to meet all requirements except that lower speed PAEB performance test requirements. Vehicles manufactured four years after the publication date of a final rule would be required to meet all requirements specified in the final rule. NHTSA proposed that small-volume manufacturers, final-stage manufacturers, and alterers would be provided an additional year of lead time for all requirements.

E. Additional Research Conducted in 2023

While past testing conducted in support of the NPRM provided ample support for the proposed performance requirements, NHTSA conducted additional research in 2023, which included an evaluation of the newest vehicles available on the market.[44] The new research confirmed that AEB and PAEB performance maintained good performance when compared with previous testing. This research used three test scenarios to evaluate the AEB performance of six light vehicles. The vehicles tested included the 2023 BMW iX, 2023 Ford F–150 Lightning, 2023 Hyundai Ioniq 5 Limited, 2024 Mazda CX–90 Turbo S, 2023 Nissan Pathfinder SL, and the 2023 Toyota Corolla Hybrid XLE. The lead vehicle testing evaluated the effects of regenerative braking settings for electric (and some hybrid) vehicles, adaptive cruise control settings, and ambient lighting conditions on the AEB performance of these vehicles.

The lead vehicle scenarios used in this research included the proposed conditions of lead vehicle stopped, moving, and decelerating. All conditions and parameters for this research were consistent with those described in the proposed rule. For nominal testing (tests not designed to investigate a particular condition or parameter) the Toyota used in this research avoided contacting the vehicle test device at all speeds tested from 10 km/h to 80 km/h (50 mph) in the lead vehicle stopped condition. The Mazda avoided contacting the lead vehicle test device in all lead vehicle stopped conditions up to 60 km/h (37.5 mph).

[44] NHTSA's 2023 Light Vehicle Automatic Emergency Braking Research Test Summary and NHTSA's 2023 Light Vehicle Pedestrian Automatic Emergency Braking Research Test Summary, available in the docket for this final rule (NHTSA–2023–0021).

BILLING CODE 4910–59–P

Table 16: Lead Vehicle Stopped Test Results
No Manual Braking
Summary (Nominal Condition)

Test Conditions	Trial #	2023 BMW iX xDrive50	2023 Ford F-150 Lightning	2023 Hyundai Ioniq 5	2024 Mazda CX-90	2023 Nissan Pathfinder	2023 Toyota Corolla Hybrid
SV[45] = 10 km/h POV[46] = 0 km/h	1	CA	CA	CA	CA	CA	CA
	2	9.6	CA	CA	CA	CA	CA
	3	CA	CA	CA	CA	CA	CA
	4	CA	CA	CA	CA	CA	CA
	5	CA	CA	CA	CA	CA	CA
SV = 40 km/h POV = 0 km/h	1	CA	CA	CA	CA	CA	CA
	2	39.2	CA	CA	CA	CA	CA
	3	40.3	CA	CA	CA	CA	CA
	4	CA	CA	CA	CA	CA	CA
	5	CA	CA	CA	CA	CA	CA
SV = 50 km/h POV = 0 km/h	1	CA	CA	CA	CA	CA	CA
	2	CA	CA	CA	CA	CA	CA
	3	CA	CA	CA	CA	CA	CA
	4	49.4	CA	CA	CA	CA	CA
	5	CA	CA	CA	CA	CA	CA
SV = 60 km/h POV = 0 km/h	1	--	12.0	1.0	CA	34.9	CA
	2	--	CA	2.5	CA	--	CA
	3	--	16.8	2.8	CA	--	CA
	4	--	CA	--	CA	--	CA
	5	--	11.1	--	CA	--	CA
SV = 70 km/h POV = 0 km/h	1	--	--	--	21.8	--	CA
	2	--	--	--	20.7	--	CA
	3	--	--	--	22.4	--	CA
	4	--	--	--	--	--	CA
	5	--	--	--	--	--	CA
SV = 80 km/h POV = 0 km/h	1	--	--	--	--	--	CA
	2	--	--	--	--	--	CA
	3	--	--	--	--	--	CA
	4	--	--	--	--	--	CA
	5	--	--	--	--	--	CA

CA – No Contact occurred during testing
The number in each cell reports the relative speed in which the vehicle tested impacted the lead vehicle test device in km/h
-- Means that no test was conducted for this parameter based on test conducted at other speeds

The Toyota, BMW, and Hyundai avoided contacting the lead vehicle test device in the lead vehicle moving scenarios for all speeds tested. The Mazda contacted the test device in a single trial at 80 km/h (50 mph) while avoiding contact in all other tested conditions including 4 other trials conducted at 80 km/h.

Table 17: Lead Vehicle Moving Test Results
No Manual Braking
Summary (Nominal Condition)

Test Conditions	Trial #	2023 BMW iX xDrive50	2023 Ford F-150 Lightning	2023 Hyundai Ioniq 5	2024 Mazda CX-90	2023 Nissan Pathfinder	2023 Toyota Corolla Hybrid
SV = 70 km/h POV = 20 km/h	1	CA	CA	CA	CA	CA	CA
	2	CA	CA	CA	CA	20.9	CA
	3	CA	CA	CA	CA	17.4	CA
	4	CA	CA	CA	CA	13.2	CA
	5	CA	CA	CA	CA	--	CA
SV = 80 km/h POV = 20 km/h	1	CA	17.4	CA	CA	--	CA
	2	CA	17.2	CA	9.4	--	CA
	3	CA	22.8	CA	CA	--	CA
	4	CA	--	CA	CA	--	CA
	5	CA	--	CA	CA	--	CA

CA – No Contact occurred during testing
The number in each cell reports the relative speed in which the vehicle tested impacted the lead vehicle test device in km/h
-- Means that no test was conducted for this parameter

For the lead vehicle decelerating scenario, the BMW did not contact the lead vehicle test device in any tested condition while the Toyota contacted the test device during three of the five trials performed at 80 km/h. Other vehicles contacted the test device as shown in the table below.

[45] SV is short for ''subject vehicle.''

[46] POV is short for ''principal other vehicle.''

Table 18: Lead Vehicle Deceleration Test Results
No Manual Braking
Summary (Nominal Condition)

Test Conditions	Trial #	2023 BMW iX xDrive50	2023 Ford F-150 Lightning	2023 Hyundai Ioniq 5	2024 Mazda CX-90	2023 Nissan Pathfinder	2023 Toyota Corolla Hybrid
SV = 50 km/h POV = 50 km/h POV decel = 0.5g headway = 12 m	1	CA	CA	CA	CA	CA	CA
	2	CA	CA	CA	CA	20.3	CA
	3	CA	CA	CA	CA	CA	CA
	4	CA	CA	4.0	CA	CA	CA
	5	CA	CA	CA	CA	CA	CA
SV = 80 km/h POV = 80 km/h POV decel = 0.5g SV-to-POV headway = 12 m	1	CA	12.6	15.2	21.5	27.1	CA
	2	CA	12.2	13.9	--	--	5.1
	3	CA	12.2	13.7	--	--	CA
	4	CA	--	--	--	--	2.9
	5	CA	--	--	--	--	2.5

CA – No Contact occurred during testing
The number in each cell reports the relative speed in which the vehicle tested impacted the lead vehicle test device in km/h
-- Means that no test was conducted for this parameter

The agency also studied lead vehicle AEB performance in darkness. Results from the dark ambient lighting tests are shown in the table below. The lead vehicle stopped scenario was used for all day/darkness comparative tests. The results observed during the dark ambient tests were largely consistent with those produced during the daylight tests. The dark versus day contact results observed for a given test speed were identical or nearly identical for the Hyundai, Mazda, Nissan, and Toyota. Where impacts occurred, the impact speeds were very close.

Table 19: Lead Vehicle Stopped – No Manual Braking
Summary (Dark Ambient Lighting)

Test Conditions	Trial #	2023 BMW iX xDrive50	2023 Ford F-150 Lightning	2023 Hyundai Ioniq 5	2024 Mazda CX-90	2023 Nissan Pathfinder	2023 Toyota Corolla Hybrid
SV = 10 km/h POV = 0 km/h	1	CA	CA	CA	CA	CA	CA
	2	CA	CA	CA	CA	CA	CA
	3	CA	CA	CA	CA	CA	CA
	4	CA	CA	CA	CA	3.0	CA
	5	CA	CA	CA	CA	CA	CA
SV = 40 km/h POV = 0 km/h	1	CA	CA	CA	CA	CA	CA
	2	CA	CA	CA	CA	CA	CA
	3	CA	CA	CA	CA	CA	CA
	4	CA	CA	CA	CA	CA	CA
	5	CA	CA	CA	CA	CA	CA
SV = 50 km/h POV = 0 km/h	1	CA	CA	CA	CA	CA	CA
	2	CA	CA	CA	CA	CA	CA
	3	CA	CA	CA	CA	CA	CA
	4	CA	CA	CA	CA	CA	CA
	5	44.2	CA	CA	CA	CA	CA
SV = 60 km/h POV = 0 km/h	1	54.6	22.8	3.7	CA	30.6	CA
	2	--	24.6	4.2	CA	--	CA
	3	--	23.7	4.2	CA	--	CA
	4	--	--	--	CA	--	CA
	5	--	--	--	CA	--	CA
SV = 70 km/h POV = 0 km/h	1	--	--	--	21.3	--	CA
	2	--	--	--	20.8	--	CA
	3	--	--	--	26.9	--	CA
	4	--	--	--	--	--	CA
	5	--	--	--	--	--	CA
SV = 80 km/h POV = 0 km/h	1	--	--	--	--	--	CA
	2	--	--	--	--	--	CA
	3	--	--	--	--	--	CA
	4	--	--	--	--	--	CA
	5	--	--	--	--	--	CA

CA – No Contact occurred during testing

The number in each cell reports the relative speed in which the vehicle tested impacted the lead vehicle test device in km/h

-- Means that no test was conducted for this parameter

The agency also studied the effects of regenerative braking settings for electric and hybrid electric vehicles on the performance of lead vehicle AEB. Again, the lead vehicle stopped test scenario was used for this comparison. The

regenerative braking settings did not have a negative effect on the performance of the tested AEB systems. As expected, performance under the highest regenerative braking settings was slightly better that the lower, or off, settings. However, the effect of regenerative brake setting on the vehicle's ability to avoid contact with the lead vehicle test device was dependent on the vehicle tested.

Table 20: Lead Vehicle Stopped – No Manual Braking Summary (Lowest Regen. Brake Setting).

Test Conditions	Trial #	2023 BMW iX xDrive50	2023 Ford F-150 Lightning	2023 Hyundai Ioniq 5
SV = 10 km/h POV = 0 km/h	1	CA	CA	CA
	2	9.6	CA	CA
	3	CA	CA	CA
	4	CA	CA	CA
	5	CA	CA	CA
SV = 40 km/h POV = 0 km/h	1	CA	CA	CA
	2	39.2	CA	CA
	3	40.3	CA	CA
	4	CA	CA	CA
	5	CA	CA	CA
SV = 50 km/h POV = 0 km/h	1	CA	CA	CA
	2	CA	CA	CA
	3	CA	CA	CA
	4	49.4	CA	CA
	5	CA	CA	CA
SV = 60 km/h POV = 0 km/h	1	--	12.0	1.5
	2	--	CA	2.2
	3	--	16.8	2.1
	4	--	CA	--
	5	--	11.1	--

CA – No Contact occurred during testing
The number in each cell reports the relative speed in which the vehicle tested impacted the lead vehicle test device in km/h
-- Means that no test was conducted for this parameter

Table 21: Lead Vehicle Stopped – No Manual Braking Summary (Highest Regen. Brake Setting).

Test Conditions	Trial #	2023 BMW iX xDrive50	2023 Ford F-150 Lightning	2023 Hyundai Ioniq 5
SV = 10 km/h POV = 0 km/h	1	CA	CA	CA
	2	CA	CA	CA
	3	CA	CA	CA
	4	CA	CA	CA
	5	CA	CA	CA
SV = 40 km/h POV = 0 km/h	1	CA	CA	CA
	2	CA	CA	CA
	3	CA	CA	CA
	4	CA	CA	CA
	5	CA	CA	CA
SV = 50 km/h POV = 0 km/h	1	CA	CA	CA
	2	CA	CA	CA
	3	CA	CA	CA
	4	CA	CA	CA
	5	CA	CA	CA
SV = 60 km/h POV = 0 km/h	1	CA	15.5	CA
	2	CA	16.1	1.3
	3	CA	11.3	CA
	4	CA	--	CA
	5	CA	--	CA
SV = 70 km/h POV = 0 km/h	1	CA	--	16.4
	2	CA	--	14.9
	3	CA	--	18.0
	4	CA	--	--
	5	CA	--	--
SV = 80 km/h POV = 0 km/h	1	CA	--	--
	2	CA	--	--
	3	CA	--	--
	4	CA	--	--
	5	CA	--	--

CA – No Contact occurred during testing

The number in each cell reports the relative speed in which the vehicle tested impacted the lead vehicle test device in km/h

-- Means that no test was conducted for this parameter

The agency also conducted additional PAEB testing. The same vehicles used for the lead vehicle testing presented above were used to evaluate their PAEB performance consistent with the proposed rule. The results of this testing

are summarized in the table below. The table provides the maximum speed tested at which the vehicle avoided contacting the pedestrian test device. Of specific note, one vehicle avoided contacting the pedestrian test device at all speeds tested. Some vehicles contacted the test device at 10 km/h but under further testing, demonstrated the ability to avoid contacting the pedestrian test device at much higher speeds. Further details of this testing and additional results are available in the report contained in the docket provided at the beginning of this final rule.

Table 22: Pedestrian AEB Performance
2023 Test Results Summary

	Dir.	Overlap	Obst.	Speed (km/h)		Lighting Condition	Pathfinder	Ioniq 5	Corolla Hybrid	iX xDrive50	F150 Lighting	CX-90
				V_{SV}	V_P							
Pedestrian Crossing Road	Right	25%	No	Any 10 - 60	5	Daylight	50	40	60	50	60	60
	Right	50%	No	Any 10 - 60	5	Daylight	60	60	60	60	60	60
				Any 10 - 60		Lower Beams	60	50	60	60	50	60
				Any 10 - 60		Upper Beams	60	50	60	60	60	60
	Left	50%	No	Any 10 - 60	8	Daylight	50	50	60	60	60	60
	Right	50%	Yes	Any 10 - 50	5	Daylight	40	40	50	50	50	40
Stationary Pedestrian	Right	25%	No	Any 10 - 55	0	Daylight	55	55	55	55	55	55
				Any 10 - 55		Lower Beams	20	50	55	55	30	55
				Any 10 - 55		Upper Beams	55	55	55	55	55	55
Pedestrian Moving Along the Path	Right	25%	No	Any 10 - 65	5	Daylight	50	60	65	65	65	65
				Any 10 - 65		Lower Beams	-	60	65	40	40	60
				Any 10 - 65		Upper Beams	-	60	65	65	65	65

- Denotes the vehicle did not avoid contacting the pedestrian test device at any tested speed.

BILLING CODE 4910–59–C

III. Final Rule and Response to Comments

A. Summary of the Final Rule (and Modifications to the NPRM)

With a few notable exceptions, this final rule adopts the performance requirements from the proposed rule. This rule requires manufacturers to install AEB systems that meet specific performance requirements. These performance requirements include the installation of an AEB system, track testing requirements for avoiding both lead vehicles and pedestrians, false activations test requirements, and malfunction indication requirements.

This final rule includes four requirements for AEB systems for both lead vehicles and pedestrians. First, there is an equipment requirement that vehicles have an AEB system that provides the driver with an FCW at any forward speed greater than 10 km/h (6.2 mph) and less than 145 km/h (90.1 mph). The FCW must be presented via auditory and visual modalities when a collision with a lead vehicle or a pedestrian is imminent. This final rule includes specifications for the auditory and visual warning components consistent with those of the proposed rule, with some modifications to keep the effectiveness of the FCW while reducing the potential costs associated with this rule for some vehicle designs. Similarly, this final rule includes an equipment requirement that light vehicles have an AEB system that applies the brakes automatically at any forward speed that is greater than 10 km/h (6.2 mph) and less than 145 km/h (90.1 mph) when a collision with a lead vehicle is imminent, and at any forward speed greater than 10 km/h (6.2 mph) and less than 73 km/h (45.4 mph) when a collision with a pedestrian is

imminent. The maximum speed of lead vehicle AEB is modified from the NPRM, which did not include upper limits on speeds. NHTSA also clarified that this requirement applies only when environmental conditions permit.

Second, the AEB system is required to prevent the vehicle from colliding with the lead vehicle or pedestrian test devices when tested according to the standard's test procedures. These track test procedures have defined parameters, including travel speeds up to 100 km/h (62.2 mph), that ensure that AEB systems prevent crashes in a controlled testing environment. The three scenarios for testing vehicles with a lead vehicle and four scenarios for testing vehicles with a pedestrian test device are finalized as proposed. The agency has finalized pedestrian tests in both daylight and darkness, while testing using the lead vehicle test device is conducted in daylight only as proposed.

Third, this final rule includes the two false activation tests, driving over a steel trench plate and driving between two parked vehicles, in which the vehicle is not permitted to brake in excess of specified amounts proposed in the NPRM.

Finally, a vehicle must detect AEB system malfunctions and notify the driver of any malfunction that causes the AEB system not to meet the minimum proposed performance requirements. The system must continuously detect system malfunctions, including performance degradation caused solely by sensor obstructions. If the system detects a malfunction, or if the system adjusts its performance such that it will not meet the requirements of the finalized standard, the system must provide the vehicle operator with a telltale notification. This final rule has also clarified that the purpose of the malfunction telltale is to provide information about the operational state of the vehicle. Some commenters understood the NPRM to have required that the malfunction telltale activate based on information about the vehicle's surroundings such as low friction road surfaces.

This final rule includes several changes to the NPRM based on the comments received:

First, NHTSA includes in this final rule an explicit prohibition against manufacturers installing a control designed for the sole purpose of deactivating the AEB system but allows for controls that have the ancillary effect of deactivating the AEB system (such as deactivating AEB if the driver has activated ''tow mode'' and the manufacturer has determined that AEB cannot perform safely while towing).

NHTSA also modifies the FCW visual signal location requirement in this final rule to increase the specified visual angle from 10 degrees to 18 degrees in the vertical direction. This change from the NPRM provides manufacturers with the flexibility to locate the visual warning signal within the typical area of the upper half of the instrument panel and closer to the central field of view of the driver. While the agency continues to believe that an FCW visual warning signal presented near the central forward-looking region is ideal, it does not consider a head-up display to be necessary for the presentation of the FCW visual signal.

In addition, NHTSA modifies in this final rule the range of forward speeds at which the AEB must operate. The NPRM required FCW and AEB systems to operate at any forward speed greater than 10 km/h. This final rule places an upper bound on the requirement that an AEB system operate of 145 km/h (90.1 mph) for FCW and lead vehicle AEB and 73 km/h (45.4 mph) for pedestrian AEB. This final rule also clarifies the environmental conditions under which the AEB system must perform to be the same environmental conditions specified in the track testing.

NHTSA also makes a minor adjustment in this final rule to the measurement method used to characterize the radar cross-section for the pedestrian test devices. It maintains the cross-section boundaries contained within the proposed rule as incorporated from ISO 19206–2:2018 but uses parts of the updated measurement method incorporated from ISO 10206–3:2021. This newer method was proposed for use in measuring the vehicle test device, while the older measurement method was proposed for the pedestrian test devices. The newer method provides for better filtration of noise by using average measurements taken at three radar heights as opposed to the single measurement height specified in the older method. This final rule modifies the measurement methods for the pedestrian test device to match the method used when characterizing the vehicle test device.

Finally, this final rule makes a few significant changes to the lead-time and phase-in requirements. Instead of the deadline proposed under the NPRM, this final rule requires that manufacturers comply with all provisions of the rule at the end of the 5-year period starting the first September 1 after this publication. This will provide manufacturers with more time to meet the requirements of this final rule, as most vehicles do not currently meet all of the performance requirements set forth in this final rule and in light of manufacturer redesign schedules. The added lead time avoids significantly increasing the costs of the rule by compelling equipment redesigns outside of the normal production cycle.

As part of this extension of the lead time, the agency has removed the phase-in approach to the PAEB performance requirements. While the NPRM proposed the most stringent PAEB requirements be met 4 years after a final rule (1 year more than all the other requirements), the agency is finalizing a 5-year lead time for all requirements (eliminating the phasing in of requirements during the lead time).

B. Application

NHTSA proposed that the new FMVSS No. 127 apply to all passenger cars and to all multipurpose passenger vehicles, trucks, and buses with a GVWR of 4,536 kilograms (10,000 pounds) or less. The agency did not propose that the new FMVSS apply to vehicles with a GVWR over 4,536 kilograms (10,000 pounds) or to include motorcycles or low-speed vehicles.

Vehicle Body Types

Several commenters requested that NHTSA consider various vehicle types in the application of the new FMVSS. The Alliance noted that the agency's analysis focused only on performance for sedan, SUV and crossover, and pickup vehicles, and did not consider the constraints associated with the installation of sensors on vehicles with certain vehicle designs such as sports cars, which may affect system capabilities based on unique design characteristics and low profile. FCA noted that the NPRM did not include the low-speed vehicle (LSV) class and supported their inclusion in this rule, in part based on the inclusion of LSVs in the most recent modifications to FMVSS No. 111 and FMVSS No. 141.

While NHTSA acknowledges the Alliance's concerns that mounting forward-looking sensors on certain vehicle body types, such as sports cars, may present some challenges, we believe that technology already present on some existing production vehicles can be adapted to address the concern. We also believe that 5 years provides adequate lead time for manufacturers to consider the changes necessary to their models to implement AEB. We further note that manufacturers are not restricted as to sensor placement. Existing production vehicles have sensors located in a variety of places. NHTSA is aware of several vehicles

equipped with radar and camera sensors mounted in the cabin near the rearview mirror. Such a sensor configuration would avoid the installation constraints imposed by small bumpers, avoid placement behind carbon fiber material, and accommodate placement further above the ground.

Regarding FCA's comment, LSVs were excluded from the scope of the final rule for several reasons. First, there are no LSVs on the market that NHTSA is aware of that are currently equipped with AEB or PAEB. This means that NHTSA was not able to procure a vehicle for testing or otherwise evaluate how a LSV would perform if equipped with AEB/PAEB. Second, there is a lack of specific safety data to support an argument that LSVs should be equipped with AEB/PAEB. NHTSA does not want to preclude such vehicles from being equipped with these safety systems, but the current safety data does not provide justification for including them in this rule. Finally, and as discussed in the FRIA, LSVs were not included due to uncertainty about the feasibility and practicability of AEB for those vehicles. Although LSVs were included in the two most recent standard of significance (FMVSS 111 Backup Camera and FMVSS 141 Sound for Electric Vehicles) without practicability concerns, we note that those standards include requirements that provide aids to assist the driver or alerts the driver. In such cases, those features do not require the vehicle to react but instead elicit a driver reaction. As these vehicles were not included in the testing conducted by the agency, our analysis is unable to characterize the performance of AEB on these vehicles. Therefore, in the absence of any data to characterize how these systems may perform on LSVs, they were not included in the final rule.

Heavier Vehicles

The Alliance and FCA commented about the interaction between the proposed standard and FMVSS Nos. 105 and 135, which regulate braking. The Alliance recommended a comprehensive review of the impact of the proposed rule with appropriate accommodations to exclude or include a cap on the applicability of the proposal based on vehicle weight. The Alliance stated that typical electronic stability control (ESC) systems may not provide the fluid flow rates needed to produce the braking performance necessary to meet the proposed rule. FCA noted that the proposed standard applies to vehicles between 7,716 pounds GVWR (the upper limit for FMVSS No. 135 application) and 10,000 pounds GVWR, opining that this proposed standard is not intended to force changes in the underlying braking performance of vehicles in that range and noting that testing has not been conducted on vehicles over 7,000 pounds GVWR. FCA suggested limiting application of proposed FMVSS No. 127 to vehicles under 7,716 pounds GVWR.

NHTSA evaluated compliance test results for FMVSS No. 135 conducted over the last several years. There were 30 vehicles included in this testing, including small sedans, large pickup trucks, minivans, SUVs and other vehicle types to which this new FMVSS would apply. The results indicate that the braking performance of nearly all vehicles was much better than what FMVSS No. 135 requires and the average deceleration for the larger pickup trucks also outperformed some of the smaller sedans, SUVs, and minivans. These test results indicate that braking performance is more than sufficient to permit compliance with this final rule without a need for braking changes or supplements. While this rule is not intended to force changes in the underlying braking performance of vehicles, the commenters stopped short of asserting that braking improvements would be necessary, stating only that improvements may be necessary. Moreover, even if underlying braking performance improvements were necessary, nothing in the comments suggests that there are any technical barriers or any other impediments that would make such improvements infeasible.

Automated Driving Systems

Several commenters suggested exempting vehicles with automated driving systems from the application of some or all of the proposed FMVSS No. 127. Volkswagen recommended exempting autonomous vehicles (AVs) from the parts of the regulation that involve displaying warnings and the parts for which manipulation of manual controls is part of the test procedure. Similarly, AVIA requested that the forward collision warning requirements not apply to AVs.

Zoox requested that the proposed FMVSS not apply to AVs. Zoox viewed the proposed rule as directed toward human drivers, and that applying it to AVs may result in unintended consequences, such as establishing emergency collision avoidance standards for AVs without considering other avoidance tools available to AVs, thereby constraining their safety capabilities.

AVIA also provided suggested changes to the proposed application language that would exclude vehicles equipped with ADS from the requirement to have an AEB system if the ADS meets the performance requirements of the proposed standard. The Alliance commented that ADS-equipped vehicles without manual controls should be exempt from the driver warning and DBS requirements, which it viewed as relevant only when there is a human driver and similarly that the DBS requirements should be applicable only if a brake pedal is installed or required to be installed in the vehicle.

NHTSA expects that ADS-equipped vehicles are capable of meeting the performance requirements of this rule, especially those related to identifying crash imminent situations with vehicles and pedestrians and applying the brakes to avoid contact. Volkswagen is correct that NHTSA is considering how to address telltales, alerts, and warnings, like FCW, in the context of vehicles driven by ADS.[47] While NHTSA continues to engage in research to support the related rulemakings evaluating the application of existing FMVSS to ADS-equipped vehicles, NHTSA is finalizing this rule for all light vehicles and will consider future modifications regarding telltales, alerts, and warnings, as well as crash avoidance standards, generally, for ADS-equipped vehicles as needed under separate rulemaking efforts.[48]

C. Definitions

The proposed rule contained key definitions to facilitate the understanding of the rule. While there were 15 proposed definitions included in section S4 of the proposed new FMVSS, this section focuses on those raised in comments.

AEB System

The NPRM defined an automatic emergency braking system as a system that detects an imminent collision with vehicles, objects, and road users in or near the path of a vehicle and automatically controls the vehicle's service brakes to avoid or mitigate the collision. Several commenters recommended changes to the definition of AEB system:

Bosch asked NHTSA to consider adopting the definition of ''Advanced Emergency Braking System (AEBS)'' used in United Nations Regulation No. 152 (UNECE R152) to promote global harmonization and enhance clarity in

[47] See *https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2127-AM07.*

[48] See *https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202304&RIN=2127-AM00.*

the terminology used across various jurisdictions.

Porsche and Volkswagen stated that the AEB system requirements throughout the NPRM require performance metrics specific to mitigating collisions with lead vehicles and pedestrians, generally not mitigating collisions with objects, but the proposed definition for AEB includes reference to ''objects'' and ''road users.'' Specifically, Porsche referred to the requirements that the vehicle is required not to apply braking when encountering a steel trench plate. Porsche expressed concern that, by including ''object,'' the AEB definition could introduce confusion in whether braking could be applied in false activation tests. Volkswagen noted that the trench plate could be categorized as an ''object.'' Bosch commented that the broad definition poses challenges in requiring that there is no collision with any ''object.''

In reference to the term ''road users,'' Porsche and Volkswagen commented that the NPRM referenced pedestrians and was not more broadly inclusive of other road-users such as bicyclists. Both recommended replacing the term ''road user'' with ''pedestrian'' to align with the proposed requirements. Bosch did not specifically address the term ''road users,'' but recommended that NHTSA replace ''object'' with ''pedestrian'' in the proposal for more clarity and consistency in the context of the FCW and AEB system.

An anonymous commenter stated that the AEB system definition does not specify what constitutes a ''crash imminent situation'' or how the system determines if the driver has not applied the brakes, or how much braking force is applied to the system. This commenter noted that these are important details that may affect the performance and effectiveness of the AEB system.

BIL requires that an FCW system alert the driver if there is a ''vehicle ahead or an object in the path of travel'' if a collision is imminent. Consistent with this definition, NHTSA defines an AEB system as one that detects an imminent collision with a vehicle or with an object. However, nothing in the definition of AEB system requires vehicles to detect and respond to imminent collisions with all vehicles or all objects in all scenarios. Such a requirement would be unreasonable given the wide array of harmless objects that drivers could encounter on the roadway that do not present safety risks.

The agency has reviewed the various definitions used in the NPRM to assess whether meaningful harmonization could be achieved with UNECE regulations. In UNECE Regulation No. 152, ''Advanced Emergency Braking System (AEBS)'' means a system which can automatically detect an imminent forward collision and activates the vehicle braking system to decelerate the vehicle with the purpose of avoiding or mitigating a collision. The definition proposed in the NPRM is functionally very similar, but uses language from BIL. Unlike UNECE Regulation No. 152, NHTSA's definition also provides a level of clarity as to where the detection of vehicles, objects, and road users must occur, that is ''in or near the path of a vehicle.''

The commenters' concern that this definition requires detection of and reaction to ''all objects'' is unfounded. NHTSA has also considered the use of the term ''road users'' in the AEB definition. NHTSA is aware of manufacturers that have designed AEB systems to detect pedestrians. However, the performance requirements make clear that this final rule requires detection and reaction to pedestrians and lead vehicles. The use of ''objects'' and ''road users'' merely identify potential hazards on a road that may require emergency braking, but are not intended to impose requirements beyond the requirements set forth in the standard.

The agency considered comments seeking inclusion of various performance requirements in the definitions section. Those comments did not explain why such a change is necessary. As a general matter of regulatory structure, NHTSA limits the definition section to defining terms; the operative regulatory text is the appropriate location for performance requirements and other directives of substantive effect.

Therefore, NHTSA adopts the proposed definition of AEB, which is defined as a system that detects an imminent collision with vehicles, objects, and road users in or near the path of a vehicle and automatically controls the vehicle's service brakes to avoid or mitigate the collision.

Forward Collision Warning

The NPRM defined forward collision warning as an auditory and visual warning provided to the vehicle operator by the AEB system that is designed to induce immediate forward crash avoidance response by the vehicle operator.

Consistent with its comment about alignment of the definition of AEB with UNECE R152, Bosch recommended that NHTSA adopt UNECE R152's Collision Warning definition for the FCW definition: ''a warning emitted by the [Advanced Emergency Brake System] AEBS to the driver when the AEBS has detected a potential forward collision.''

NHTSA has finalized the definition of FCW as an auditory and visual warning provided to the vehicle operator by the AEB system that is designed to induce immediate forward crash avoidance. This definition provides clarity that both an auditory and visual warning are necessary for a complete warning that is most likely to reengage a distracted driver. For purposes of the test procedure established in this final rule, if only the visual or only the auditory component of the FCW is provided, then the FCW onset has not happened, and the test procedure steps will not take place until both the auditor and visual components are both in place. As such, the UNECE R152 definition suggested by the commenters does not provide this needed clarity.

Zoox also recommended changes to the FCW definition to clarify applicability to conventional vehicles with human drivers only. As noted above, NHTSA is finalizing this rule for all light vehicles and will consider future modifications regarding telltales, alerts, and warnings, as well as crash avoidance standards, generally, for ADS-equipped vehicles as needed under separate rulemaking efforts. Because NHTSA is not adjusting requirements to accommodate ADS, no definition changes are required to address this issue.

Onset

Commenters requested clarification or addition to the definitions to further clarify the proposed requirements and test procedures. The NPRM defined ''forward collision warning onset'' as the first moment in time when a forward collision warning is provided. Automotive Safety Council sought clarification whether this would be measured in terms of a signal output on the Controller Area Network (CAN) bus, or measured by sound physically emitted from the speaker. NHTSA clarifies that FCW onset would be determined via measurement of the FCW auditory signal sound output within the vehicle cabin and the illumination of the FCW visual signal. CAN bus information would not be used to assess FCW onset.

The NPRM did not provide a definition of braking onset. Humanetics stated that the term ''vehicle braking onset'' needed further clarification in all test protocols. Humanetics suggested a target value of speed change or deceleration value should be used as an indicator of the time of braking onset.

NHTSA has decided to clarify the term ''vehicle braking onset'' in the regulation text as Humanetics suggested, by defining the ''subject vehicle braking onset'' as the point at which the subject vehicle achieves a deceleration of 0.15g due to the automatic control of the service brakes. To ensure clarity in the PAEB test procedure, NHTSA has used the term ''subject vehicle braking onset'' to clarify that NHTSA is referring to the vehicle braking onset of the subject vehicle. The 0.15g deceleration was adopted based on the agency's experience conducting AEB testing as this value has proven a reliable marker for PAEB onset during track testing.[49]

Other Definitions

NHTSA does not believe that any further additional definitions are necessary for manufacturers to understand the performance requirements of the standard or their obligations. NHTSA believes that terms appearing within the proposed definitions are sufficiently clear from the context of the regulation. For example, we believe the meaning of ''crash imminent situation'' is discernable from close review of the performance requirements, including the test procedures; from these, the commenter can determine what the agency would consider crash imminent for the set of testable ranges included in this rule.

Finally, NHTSA acknowledges Consumer Reports' and AAA's requests to limit the use of the terms CIB and DBS. NHTSA has already done this by excluding those terms from the regulatory text. While NHTSA used CIB and DBS throughout the preamble to the NPRM and in this final rule, it is doing so because these terms are frequently used by industry, and their use in the preamble helps readers understand what NHTSA is saying, particularly in the context of prior research and NCAP, which use those terms.

D. FCW and AEB Equipment Requirements

NHTSA proposed that an FCW must provide the driver warning of an impending collision when the vehicle is traveling at a forward speed greater than 10 km/h (6.2 mph). Similarly, the NPRM require a vehicle to have an AEB system that applies the service brakes automatically when a collision with a lead vehicle or pedestrian is imminent at any forward speed greater than 10 km/h (6.2 mph). NHTSA stated in the NPRM that this minimum speed should not be construed to prevent a manufacturer from designing an AEB system that activates at speeds below 10 km/h (6.2 mph).

This proposed requirement was described as an equipment requirement with no associated performance test. No specific speed reduction or crash avoidance would be required. However, this requirement was included to ensure that AEB systems are able to function at all times, including at speeds above those NHTSA proposed as part of the performance test requirements where on-track testing is currently not practicable. NHTSA received comments regarding both the minimum required activation speed and the lack of maximum activation speed.

1. Minimum Activation Speed

Comments

MEMA supported not having FCW and AEB performance requirements at a speed below 10 km/h (6 mph), opining that AEB systems do not offer consistent performance at such low speeds.

Bosch and Volkswagen suggested changing the FCW minimum activation speed to 30 km/h. Bosch believed that FCW may not be beneficial at lower speeds because the AEB system proves to be a sufficient solution. Bosch stated that at lower velocities no driver reaction is required because the AEB intervention can fully avoid the collision after the ''last time to steer'' has already occurred. According to Bosch, as the vehicle speed increases, from 30 km/h upwards, the last point to steer gradually moves to a point after the last point to brake. In effect, a driver warning then becomes beneficial, and FCW can help the driver take appropriate action to avoid or mitigate a collision.

Volkswagen stated that setting a requirement for FCW at low speeds can lead to high false positive rates. Volkswagen also noted that meeting the proposed performance requirements depended on the FCW being issued before the activation of AEB, and could lead to very sensitive system behavior, especially for PAEB. Volkswagen suggested increasing the minimum FCW activation speed to 30 km/h, but suggested it would still be acceptable to display the FCW symbol simultaneously with AEB activation at speeds below 30 km/h to make the driver aware of the event that just occurred.

The Center for Auto Safety disagreed with the 10 km/h minimum speed threshold saying that it was not clear why it was selected. The Center for Auto Safety commented that PAEB should be activated as soon as the vehicle is shifted into gear to avoid injurious or fatal rollovers of children and other hazards. Consumer Reports commented that it understood the technical reasons for the proposed minimum speed of 10 km/h (6.2 mph), but expressed concern that such a lower speed bound would fail to address the issue of what it described as ''frontover'' incidents.[50] Consumer Reports said there had been an increase in ''frontover'' incidents since 2016, and that it believed that the increasing market share of larger vehicles with increased blind zones was correlated with this increase.

Agency Response

NHTSA is finalizing a minimum activation speed of 10 km/h as proposed. The agency considered increasing this minimum to 30 km/h, as suggested by some commenters, to avoid unwanted and unnecessary alert at low speeds. However, after considering the potential impacts of such a modification, particularly the safety of pedestrians, the agency is finalizing the minimum activation speed as proposed for the forward collision warning. This 10 km/h minimum threshold is also harmonized with UNECE Regulation No. 152. Furthermore, as stated in the NPRM, 6 of 11 manufacturers whose owner's manuals NHTSA reviewed indicated that their AEB system have a minimum speed below 10 km/h. NHTSA is encouraged that manufacturers are choosing to have lower speed thresholds for AEB functionality.

As for frontover crashes, NHTSA agrees with Consumer Reports about the importance of understanding driver visibility and about the need to reduce such crashes. Additional research is needed to develop accurate and rigorous methods of evaluating direct visibility

[49] *https://www.regulations.gov/document/NHTSA-2021-0002-0002.*

[50] There is not yet a finalized definition of ''frontover'' that is used within NHTSA or outside of NHTSA, and NHTSA is currently researching how this crash type should be defined. As NHTSA previously indicated, until more data is gathered via the Non-Traffic Surveillance (NTS) system, actual frontover crash counts are difficult to confirm due to the challenges law enforcement faces in distinguishing these crashes from other forward moving vehicle impacts with non-motorists and to the locations where these crashes often occur. For example, a forward moving vehicle crash involving a driver turning into a driveway and striking a child playing in the driveway would typically not be considered a frontover; but if that driver struck the child while pulling out of a garage (having backed into the garage), it would be considered a frontover. These nuances pose difficulties for law enforcement to accurately capture frontover incidents which, in turn, complicates our data collection. Additionally, frontover crashes frequently occur in driveways and parking lots that are not located on the public trafficway; thus, law enforcement may not report these occurrences using a crash report.

from the driver's seat. Research is also needed to better understand the safety problem and the scenarios associated with forward blind zones and frontover crashes. Beginning in January 2023, two new non-traffic crash data elements related to backovers [51] and frontovers were added to the agency's Non-Traffic Surveillance System, which will enhance evaluation of the scope and factors associated with frontover crashes.

2. Maximum Activation Speed

Comments

The National Transportation Safety Board (NTSB) supported the proposed requirements for FCW, specifically pertaining to the necessity of the warning at all speeds above 10 km/h, but the NTSB stated that FCW activation must never delay AEB engagement. NTSB stated that its support was rooted in several NTSB investigations of vehicles operating in partial automation mode at the time of the crash.

In contrast, many commenters raised substantial concerns about the proposed NPRM requirement that FCW and AEB function, at least at some level, at all speeds and under all environmental conditions. Among these concerns was that the requirement would not meet various aspects of the Safety Act.

The Alliance disagreed with the agency setting undefined performance requirements that are not stated in objective terms consistent with 49 U.S.C. 30111 and urged NHTSA to provide clarification when issuing a final rule that compliance verification will be measured only by defined test procedures that meet established criteria for rulemaking. It objected to what it viewed as undefined performance requirements without a clearly demonstrated safety need that create significant challenges from a product development perspective, making it unclear whether or how NHTSA might seek to verify compliance. Without defined and objective criteria, the Alliance thought that policy uncertainty would create ambiguity about potential enforcement actions as there would be no clear parameters to reliably measure performance.

The Alliance suggested that a defined upper bound or maximum operational speed for the AEB/PAEB system was needed due to the possible unstable vehicle dynamics that could result from hard braking at very high speeds. Furthermore, the Alliance opposed open-ended performance requirements through regulation without objective test procedures, noting that it becomes increasingly more challenging to provide significant levels of speed reductions at higher speeds, and it viewed the expectation that manufacturers are capable of providing undefined levels of avoidance at all speeds as neither practicable nor reasonable. According to the Alliance, requirements that exceed the current speed ranges must be supported by relevant data to support practicability and must include defined and objective test procedures. The Alliance noted that the complexity of designing systems capable of going beyond what the agency proposes to test would likely result in significant development costs that are not accounted for in the agency's cost-benefit analysis and that would add unnecessary costs for consumers, while diverting research and development efforts from other priority areas that may yield greater improvements in vehicle safety.

Multiple automakers expressed similar concerns, some recommending that NHTSA limit AEB activation to maximum speeds and several specifying suggested upper bounds. For example, Honda suggested that NHTSA limit AEB activation to when the vehicle is traveling at maximum 135 km/h (84 mph) when approaching a lead vehicle traveling at maximum 75 km/h (47 mph) and limit pedestrian AEB activation to when the vehicle is traveling at maximum 88 km/h (55 mph). Porsche suggested that for the lead vehicle, DBS apply to speeds above 100 km/h (62 mph) and for pedestrians to speeds above 65 km/h (40 mph), and that crash imminent braking (CIB) be required to operate between 10 km/h (6 mph) and 100 km/h (62 mph) for lead vehicle and between 10 km/h (6 mph) and 65 km/h (40 mph) for pedestrian. Porsche also provided suggested regulatory text.[52]

NTSB expressed similar concerns about the need for testing, stating that without a dedicated test protocol or an explicit statement about the extent of operational functionality, broader capabilities (above the testing requirements) remain only presumed and not necessarily expected. NTSB encouraged NHTSA to clarify its intent and expectations for system performance in scenarios and conditions outside the proposed test-track compliance testing by considering additional testing or other compliance tools to examine the performance of AEB systems under other real-world conditions, and particularly whether the operational functionality would extend to non-tested hazards such as traffic safety hardware, bicyclists and motorcyclists, and vehicles with untested profiles or at varying angles and offsets.

Commenters raised potential technical challenges to effective implementation of the proposed requirement. For example, Honda was concerned about AEB and radar sensor limitations when operating at high speeds—mainly the complex interdependency between speed and the distance and accuracy at which objects must be detected to be avoided (or even to mitigate a crash). Honda noted that higher speeds mean that objects will need to be detected at greater distances, and at greater distances there is less image resolution, greater positional error, and greater impact from things like roadway geometry. Honda and Porsche stated that requiring braking to occur at unrestricted high speeds leads to misidentification of objects and increases false positive activations.

Honda further asserted that camera resolution is limited by the pixel count on the image capture chip and that at longer distances, the number of pixels for an object will be reduced, resulting in blur that makes it difficult to detect objects (the blur can be further exacerbated by the designed focal length of the lens). Further, Honda stated that a higher resolution can be achieved only through new sensor hardware that would require further developmental work as well as more processing power, including a change of imaging processing electronic control unit (ECU). Honda stated that for camera-radar fusion systems, small errors in the fusion algorithm are amplified at higher speeds (due to the longer distances) and could compromise the system's performance. Additionally, according to Honda, these reductions in sensor accuracy significantly increase the risk of misidentification of potential objects and may lead to excessive false positive activations, potentially creating negative safety consequences. This could include situations where the system mistakenly recognizes the same lane as the adjacent lane or roadway objects as other vehicles.

Other commenters also raised concerns about the potential for false activations caused by the need for AEB to operate at very high speeds. For example, Volkswagen commented that false activation becomes more of a risk as speeds increase, and that these risks

[51] NHTSA has previously defined backover crashes as crashes where non-occupants of vehicles (such as pedestrians or cyclists) are struck by vehicles moving in reverse. See *https://www.federalregister.gov/documents/2014/04/07/2014-07469/federal-motor-vehicle-safety-standards-rear-visibility.*

[52] *https://www.regulations.gov/comment/NHTSA-2023-0021-0868.*

are not controllable, as defined in ISO 26262.

Commenters raised concerns about whether braking was the most appropriate avoidance maneuver in high-speed scenarios. Honda was concerned that AEB activation might interfere with other technologies such as the Automatic Emergency Steering. Mitsubishi, and Toyota echoed the Alliance's concern that in some situations AEB activation while traveling at high speed may induce unstable vehicle dynamics. Mitsubishi stated that these situations may occur due to unfavorable interactions with road surface conditions, road curvature, or for other unpredictable reasons. Mitsubishi thought that such activation could also lead to unexpected outcomes for a vehicle following the subject vehicle.

Rivian stated that if post-crash review is used to assess compliance, it may introduce a number of uncontrollable or subjective variables into the compliance evaluation. Rivian opined that post-crash review would necessarily involve evaluation of a motor vehicle that is no longer a new motor vehicle and that may have been modified or altered in a manner to affect the AEB performance. It further noted that varying environment or roadway conditions could also impact the AEB performance and, without a proper comparison using reference test equipment, it would be difficult to identify discrepancies between the expected AEB results and the actual results, limiting the technical effectiveness of a post-crash review.

Commenters suggested a number of different solutions to resolve their concerns. Most requested that the all-speeds requirement be removed. Alternatively, Honda and others (as noted earlier) asked that NHTSA establish a maximum speed at which AEB detection performance is assessed according to an established test procedure. Volkswagen asked that NHTSA exclude activation against vulnerable road users at high speeds, believing it would decrease false positive rates significantly. Volkswagen thought this could be justified as pedestrians would not be expected on the roads with these higher speeds.

Agency Response

Authority Under the Safety Act

Various commenters asserted that performance requirements without objective test criteria were inconsistent with the Safety Act's requirements for objectivity and practicability. NHTSA believes that these assertions reflect a misunderstanding of the proposal. Essentially, NHTSA proposed specific performance requirements for AEB within a defined range of speeds (accompanied by specific testing procedures) and, separately, an equipment requirement—*i.e.,* a requirement for a functioning vehicle AEB system. The proposed requirement for a functioning AEB system at all speeds was an equipment requirement, not a performance requirement. Case law supports that where a performance standard is not practical or does not sufficiently meet the need for safety, NHTSA may specify an equipment requirement as part of an FMVSS.[53] Testing at high speeds is not practical due to the dynamics of such testing and testing equipment limitations. As detailed in the NPRM, the testing requirement upper speeds are based on the capability to safely and repeatably conduct testing. The testing devices can only be driven, and can only tolerate impacts, up to certain speeds. These edge speeds are the main limiting factor for the upper bound of the testing speeds, as testing above those speeds would be impractical. NHTSA has previously specified an equipment requirement without an accompanying test procedure. For example, under FMVSS No. 126, NHTSA issued an equipment requirement for understeer and explained why a performance test for understeer was too cumbersome for the agency and the regulated community.[54] In the final rule for FMVSS No. 126, NHTSA stated that historically, ''the agency has striven to set motor vehicle safety standards that are as performance-based as possible, but we have interpreted our mandate as permitting the adoption of more specific regulatory requirements when such action is in the interest of safety.'' [55]

There are other FMVSS that contain equipment requirements, sometimes in addition to performance requirements. FMVSS No. 111 has several requirements that are equipment requirements. S5.1 of FMVSS No. 111 requires that each passenger car be equipped with an inside rearview mirror of unit magnification, which is the equipment requirement without an associated test procedure. S5.3 requires that any vehicle that has an inside rearview mirror that does not meet the performance requirements for field of view included in S5.1.1 must also have an outside rearview mirror meeting certain performance requirements. FMVSS No. 135 requires that the service brakes shall be activated by means of foot control. This is an equipment requirement in an FMVSS that also has performance requirements. S5.1 of FMVSS No. 224, ''Rear impact protection,'' requires trailers and semitrailers with a GVWR of 4,536 kg or more to be equipped with a rear impact guard certified as meeting FMVSS No. 223, ''Rear impact guards.''

Technical Concerns

Various commenters raised concerns about technical limitations that might create challenges for AEB systems at high speeds, such as sensor limitations, false activations, and whether hard braking was an appropriate response at higher speeds.

NHTSA is aware, from a review of owner's manuals, that many manufacturers have equipped their vehicles with AEB systems that activate at speeds higher than the testable ranges NHTSA proposed. As an example, the 2022 Toyota Prius Prime owner's manual informs vehicle owners that the maximum AEB activation speed for its system is 180 km/h (112 mph). Other examples include: the 2023 Hyundai Palisade lists the maximum AEB activation speed as 200 km/h (124.27 mph), the 2018 Tesla Model 3 Dual Motor lists the maximum AEB activation speed as 150 km/h (93.2 mph), the 2021 Volvo S60 lists the maximum AEB activation speeds as 115 km/h (71.4 mph), the 2021 Ford Bronco lists the maximum AEB activation speed as 120 km/h (74.5 mph), and the 2022 Lexus NX 250 lists a maximum AEB activation speed of 180 km/h (111.8 mph). This demonstrates that it is common practice for AEB systems to function above the testable range of speeds.

The agency considered comments asserting that higher travel speeds require longer sensing ranges. However, the equipment requirement does not specify a particular speed reduction or level of avoidance. The agency considered the kinematics for an AEB system installed on a vehicle that meets the track test requirements at 80 km/h without manual braking. For a vehicle with automatic initiated deceleration capabilities of 0.7g, in a lead vehicle stopped situation, the brakes must be applied at a distance of approximately 37 m (equates to a time-to-collision of 1.66 s). In such a situation, the vehicle's sensor range would need to demonstrate capabilities at a distance of at least 37 m. In a similar rear end collision situation with the vehicle traveling at 145 km/h and an identical detection

[53] *Chrysler Corp.* v. *Dep't of Transp., OT,* 515 F.2d 1053 (6th Cir. 1975) (holding that NHTSA's specification of dimensional requirements for rectangular headlamps constitutes an objective performance standard under the Safety Act).

[54] 72 FR 17236 (Apr. 6, 2007).

[55] *Id.* at 17299.

range of 37 m, the time-to-collision would be only 0.91 s. If the vehicle applied the same 0.7g deceleration at the same 37 m distance, a collision would not be avoided. A theoretical collision would occur with the vehicle impacting the stopped vehicle at 119 km/h (74 mph). However, the vehicle would have an AEB system that applied the brakes when a crash is imminent, as the proposal would require.

Requiring that the AEB system function at higher speeds has significant safety benefits. According to the injury risk curve used in the FRIA available in this docket, the probability of a fatality occurring in a rear-end collision where the striking vehicle is impacting at 90 mph is almost 20 percent. That probability is reduced to 6.8 percent for a travel speed of 74 mph. That reduction in fatality risk is afforded with little to no additional sensing system capabilities beyond what is required to satisfy the track tested requirements. In other words, if the AEB system activates at 90 mph and slows the vehicle down by just 16 mph, the risk of a fatality declines significantly. If the system were deactivated at speeds above the test procedure limit of 62 mph, many more fatalities would occur than if the system is activated and functioning with the capabilities required to satisfy the track tested requirements. Beyond 145 km/h (90.1 mph), however, the expected safety benefits are greatly diminished, primarily because very high travel speeds are relatively uncommon and currently above legal operating speeds in the U.S.

NHTSA does recognize that pedestrian crash interactions are much less straightforward kinematically than a lead vehicle rear-end crash interaction. This is because the pedestrian may be moving in any number of directions in front of the vehicle, including suddenly darting in front of a vehicle, making detection and mitigation more challenging as speed increases. In such situations, the agency agrees with commenters that it is not practical to require an alert and braking at speeds greatly above those for which the track test applies. For this reason, this final rule reduces the speed range for pedestrian detection functionality to any speed greater than 10 km/h (6.2 mph) and less than 73 km/h (45.4 mph). Similarly, for pedestrian AEB functionality, this final rule reduces the upper end speed for which alerts and braking are required to 73 km/h (45.4 mph). This speed range balances practicability and safety.

Post-Crash Review

As for Rivian's comment on post-crash review, NHTSA can determine compliance with this equipment requirement through visual observation and other information, if requested from the manufacturer. Post-crash review is an important tool to the agency. NHTSA acknowledges Rivian's discomfort with post-crash review being considered as a primary tool for compliance purposes, but NHTSA does not believe post-crash review will be necessary to enforce this requirement. Instead, NHTSA believes it can rely on visual observation, manufacturer test results used as a basis for certification, and other information to determine whether a vehicle meets this equipment requirement.

Conclusion

After careful consideration and in response to commenters stating that there was not a safety need justifying the lack of a maximum speed cap on this equipment requirement, NHTSA has decided to modify the proposed requirement. The agency recognizes that while vehicles are capable of very high speeds, the current maximum speed limit in the United States is 85 mph. With this in mind and in response to comments urging a speed cap for AEB operation, NHTSA decided to require that AEB systems operate (*i.e.,* warn the driver and apply the brakes) at speeds up to 145 km/h (90.1 mph) for lead vehicle detection and 73 km/h (45.4 mph—based on the overall complexity of detecting and differentiating between an imminent pedestrian crash and a pedestrian encounter that is unlikely to result in a crash, such as when a pedestrian is located on the sidewalk) for pedestrian detection. NHTSA also believes that adopting this speed cap is consistent with the agency's analysis of the safety problem and with NHTSA's goals of resolving as much of the safety problems as possible.

NHTSA believes this requirement is feasible, particularly in light of the absence of any performance requirements (for example, that a vehicle brake automatically to avoid contact) other than at the speeds tested in the performance requirements specified in this standard. This final rule simply requires that an AEB system function to warn and apply the brakes at speeds up to 145 km/h (90.1 mph) for FCW and lead vehicle AEB. The agency is not preventing manufacturers from having FCW activate at speeds above 145 km/h (90.1 mph). NHTSA is aware from recent research into owner's manuals that many AEB systems operate at speeds above the testable range, and NHTSA wants to ensure that manufacturers have the flexibility to provide FCW (and AEB) at speeds above those included in this final rule. This maximum required activation speed addresses the concerns raised by commenters about a requirement without an upper bound.

3. Environmental Conditions

In the NPRM, NHTSA explained that this equipment requirement was intended to complement the performance requirements by, among other things, ensuring that AEB systems continue to function in all environments, not just the test track environment. Unlike track testing, real world traffic scenarios may involve additional vehicles, pedestrians, bicyclists, buildings, and other objects within the view of the sensors and should not negatively affect their operation.

NHTSA received several comments expressing concern about the unspecified environmental conditions included in the NPRM.

NHTSA is committed to establishing performance requirements that are as reflective of the real world as possible, and that encourage manufacturers to develop robust AEB systems with sufficient resiliency to handle the widely variable scenarios they are intended to handle. In general, NHTSA is concerned that high system brittleness will not provide the maximum safety benefits and could be confusing to the public because of expectations about how AEB systems should work. The language of the NPRM sought to provide safety under environmental conditions outside of those specified in a track testing environment.

That said, NHTSA agrees with commenters that the expectation that the AEB system work in unspecified environments should be clarified for manufacturers to certify that their vehicles will meet the equipment requirement established by this final rule. There are environmental conditions that may preclude the safe application of automatic braking, and to a lesser extent warnings. However, the complexity of conditions and combination of conditional factors make it difficult to clearly enumerate those conditions. Therefore, this final rule now clearly specifies the conditions in which the systems are expected to perform to meet the equipment requirement are those conditions specified for testing the performance requirements. Notwithstanding this specificity, NHTSA encourages manufacturers to continue working

toward delivering AEB systems that are robust and that function in as many real-world environments as possible.

The Utah Public Lands Alliance commented that the proposed rule did not take into account the complexities of off-road environments, such as obstacles, mud, rocks, and varying slopes, which may render the AEB less effective or even cause false alarms, disrupting the driving experience. NHTSA notes that the final rule does not include off-road environments as a required aspect of AEB performance because the agency's authority under the Safety Act focuses on the on-road environment.

E. AEB System Requirements (Applies to Lead Vehicle and Pedestrian)

1. Forward Collision Warning Requirements

Because the window of time that FCW affords a driver in a crash-imminent situation is small, the proposed warning characteristics were intended to facilitate quick direction of the driver's attention to the roadway in front of them and to compel the driver to apply the brakes assertively. The FCW criteria proposed were based on many years of warning research and vehicle crash avoidance research conducted by NHTSA and others as described in the NPRM. The criteria seek to achieve an effective warning strategy that is consistent across vehicle models and proven by research to promote the highest likelihood of drivers quickly understanding the situation and responding efficiently to avoid a crash.

Comments

Commenters generally supported a requirement for an FCW to be presented for lead vehicle and pedestrian scenarios. However, a majority of commenters preferred more flexibility of FCW implementation than is afforded by the requirements, as summarized below.

Multiple commenters were opposed to the degree of specificity included in the proposed FCW requirements. These commenters thought that the state of varied implementation of FCW that exists currently was sufficient. For example, Volkswagen opined that the regulation ''should specify the warning modes (visual, auditory, optionally haptic), but leave the implementation up to the manufacturer if the warning is easily perceivable and visually distinguishable from other warnings.'' Volkswagen thought that variation in FCW strategy across manufacturers would not be a problem since manufacturers ''explain their warning strategy in their owner's manuals.'' Similarly, the Alliance contended that U.S. customers may be ''already familiar with the ISO symbol and flashing alert'' and that it ''would be beneficial to safety'' for NHTSA to allow flexibility for manufacturers to select the visual warnings deemed to be most effective in the context of the overall vehicle HMI.

IIHS cited its own research as a basis for contending that the proposed FCW ''design requirements are unnecessarily overly prescriptive'' given that ''existing industry practices for FCW are not only effective for preventing crashes but are also acceptable and understandable to drivers.'' IIHS highlighted its crash data analyses for FCW-equipped vehicles stating, ''Our analyses of police-reported crashes and insurance loss data indicate that most FCW systems are effective for preventing rear-end crashes despite disparate designs. Cicchino (2017) examined rear-end crash involvement rates for vehicles with FCW from five automakers relative to vehicles without the system. The presence of FCW was associated with statistically significant reductions in rear-end crash involvement rates for three of the five automakers.''

Some commenters suggested that the FCW requirements should more closely follow other related standards. Ford recommended establishing FCW requirements similar to existing AEB regulations from Europe (UNECE R152 [56]), Australia (ADR98 [57]), and Korea (KMVSS [58]) instead of restricting the individual components of the warning. Hyundai opposed ''overly specifying details for FCW and oppose[d] the use of SAE J2400 standards (particularly 10-degree vision cone provision).'' Porsche's comments sought additional flexibility and alignment with UNECE Regulation No. 152.

Lastly, multiple commenters voiced support for standardization of FCW characteristics. The GHSA indicated support for FCW standardization, stating that ''increased consistency will bolster the safety impact of these features as drivers become more accustomed to what to expect and how to react when these systems are engaged.'' AAA also expressed support for standardization, stating that ''consumers would find it beneficial to standardize visual alert characteristics. . . . such as the location of the warning.'' AAA cited its previous testing experience that found ''characteristics among vehicles significantly vary with some warnings hardly noticeable relative to visual warnings presented in other vehicles.'' As a result, AAA urged NHTSA to ''consider standardization requirements for visual alerts to promote consistency and understanding for all drivers, particularly hearing-impaired drivers who may not perceive an auditory signal.''

Agency Response

NHTSA notes the general support from commenters for requiring some kind of FCW to be presented prior to AEB activation. The point of FCW is to elicit a timely and productive crash avoidance response from the driver, thereby mitigating or, if possible, avoiding the need for AEB to intervene in a crash-imminent situation. The proposed FCW characteristics outlined in the NPRM are based on more than 35 NHTSA research efforts related to crash avoidance warnings or forward collision warnings conducted over the past nearly 30 years. Other research, existing standards (ISO Standards 15623 and 22839), and SAE documents (J3029 and J2400) also were considered as input for the proposed requirements. While multiple commenters sought flexibility for automakers to use an FCW of their own preference in lieu of one conforming to the proposed specification, no safety data were provided concerning consumers' degree of understanding of the wide variety of existing FCW implementations—just generalized statements about consumer familiarity. NHTSA does not view these arguments as sufficient to overcome the value of standardization as a means of ensuring consumer familiarity.

Data from NHTSA's 2023 AEB testing showed that each of six test vehicle models from different manufacturers used a different FCW visual signal or symbol. Only one model used the ISO FCW symbol. FCW visual symbols that differ by manufacturer and, in some cases across models from the same manufacturer, are likely to lead to confusion among consumers. The observed substantial variety in existing FCW implementations highlights the need for improved consistency of FCW visual symbols to increase efficient comprehension of crash-imminent warnings by vehicle operators and aid them in understanding the reason for

[56] UN Regulation No 152—Uniform provisions concerning the approval of motor vehicles with regard to the Advanced Emergency Braking System (AEBS) for M1 and N1 vehicles [2020/1597] (OJ L 360 30.10.2020, p. 66, ELI: *http://data.europa.eu/eli/reg/2020/1597/oj*).

[57] Australian Design Rule, Vehicle Standard (Australian Design Rule 98/01—Advanced Emergency Braking for Passenger Vehicles and Light Goods Vehicles) 2021.

[58] Korean Motor Vehicle Safety Standard (KMVSS) Article 15–3, ''Advanced Emergency Braking Systems (AEBS).''

their vehicle's (or, indeed, an unfamiliar rental vehicle's) active crash avoidance intervention. Allowing for individual design choices—even those with positive safety records—does not address this important safety consideration.

Such confusion has also been documented by past research. Research by industry published in a 2004 SAE paper focused on comprehension testing of active safety symbols and assessed the ISO FCW symbol and the SAE J2400 FCW symbol to assess their ability to communicate the idea, ''Warning: You may be about to crash into a car in front of you.'' Results of that research showed the ISO FCW symbol to have 45 percent ''high comprehension'' and the SAE J2400 symbol to have 23 percent high comprehension. However, while high comprehension was noted for the lead vehicle crash scenario, NHTSA is not aware of any data supporting effectiveness of the ISO FCW symbol for communicating the idea of an impending forward pedestrian crash.'' [59]

NHTSA acknowledges the research by IIHS showing crash reduction benefits from some existing FCW designs. IIHS research results found that some automakers' FCW designs were associated with higher crash reductions than others. However, this research did not evaluate FCW characteristics by automaker or by model for vehicle models it studied and whether such characteristics may have contributed to FCW effectiveness differences, so care should be taken when drawing conclusions. Regardless, while the IIHS studies have shown some existing FCW in light vehicles are effective for preventing rear-end crashes, research does not support an argument against taking other measures to increase FCW effectiveness, as this action seeks to do. It is likely that increasing the consistency of FCW characteristics and standardization of the primary warning signals across vehicles and models will lead to benefits beyond those documented to date due to increased driver understanding of the meaning of FCW signals.

The agency disagrees with Volkswagen's comment that explanations in the owner's manual adequately inform consumers about manufacturer-specific FCW signals. A British study found that only 29% of motorists surveyed had read their car handbook in full.[60] That same study examined owner's manual word counts and estimated that the time required to read some of the longest would take up to 12 hours. An April 2022 Forbes article states that ''the average new-vehicle's owners' manuals, which, concurrent with the complexity of contemporary cars, have become imposingly thick and mind-numbing tomes of what should be essential information... remain unread in their respective models' gloveboxes.'' [61] With these concerns in mind, NHTSA does not believe that owner's manual information is an acceptable substitute for standardization of this important safety functionality across all vehicles.

After careful review of these comments, NHTSA has decided to adopt a majority of the proposed FCW requirements unchanged as described in the following sections.

a. FCW Signal Modality

NHTSA proposed that FCW modalities and related characteristics of auditory and visual components be the same for lead vehicle AEB and PAEB performance, and that the FCW be presented to the vehicle operator via at least two sensory modalities—auditory and visual. The FCW auditory signal was proposed to be the primary means used to direct the vehicle operator's attention to the forward roadway. NHTSA did not propose to require a haptic FCW signal component but invited comment on whether requiring FCW to contain a haptic component presented via any location may increase FCW effectiveness or whether an FCW haptic signal presented in only one standardized location should be allowed.

Comments

Of those commenting on FCW signal modality, all supported a multimodal FCW signal strategy. Multiple commenters including NTSB, Consumer Reports, Ford, GHSA, Honda, MEMA, and Porsche expressed support for the combination of auditory and visual warning modalities that was proposed by NHTSA. For example, NTSB expressed support for visual and auditory warning, and noted several NTSB investigations in which visual warnings were found to be ineffective in capturing drivers' attention. GHSA expressed support for requiring standardized auditory and visual warnings when a collision is imminent, believing that increased consistency would bolster the safety impact of these features. Ford supported an auditory and visual alert based on their experience implementing an FCW system. Honda stated that a multimodal auditory and visual warning provided sufficient redundancy. Consumer Reports also highlighted the importance of providing a visual warning for those who are hearing impaired, who are listening to music, or are otherwise distracted.

The remaining supporters of the multimodal approach preferred the flexibility to use any combination of possible modalities (auditory, visual and haptic). These included the Alliance, ASC, Bosch, GM, HATCI, and Rivian. For example, the Alliance agreed with the agency's conclusion that the auditory signal should be the primary means of communicating with the driver, but expressed support for allowing warnings to be provided using any combination of two of the three alert modalities, with a third allowable, but not required. ASC recommended that the warnings be aligned with UNECE Regulation No. 152. ASC and ZF also cited research showing FCW with auditory and haptic components prompt a quicker driver reaction time than FCW with auditory and visual components.

Ford and MEMA agreed that OEMs should be permitted to supplement the primary auditory and visual FCW signal modalities with a haptic warning component. Bosch encouraged NHTSA to include haptic as one of the warning modes, citing the potential for advantages in loud environments or with hearing impaired individuals. Volkswagen agreed with NHTSA's proposal to not require an FCW haptic component, but clarified that if haptic was required, then only two out of the three warning types should be required. HATCI requested that NHTSA permit haptic signals to be used as the primary or secondary warning, stating that haptic warnings draw the driver's attention to the hazard without requiring them to identify a warning symbol with their eyes.

Consumer Reports suggested that a haptic signal may cause driver confusion because haptic steering signals are also used by many lane departure warning systems, which activate more frequently. Along the same line, Porsche noted its desire ''to avoid causing driver confusion related to other safety systems where haptic signals may be more appropriate (*e.g.,*

[59] Campbell, John & Hoffmeister, David & Kiefer, Raymond & Selke, Daniel & Green, Paul & Richman, Joel. (2004). Comprehension Testing of Active Safety Symbols. 10.4271/2004–01–0450.

[60] ''Car Handbooks Are Longer Than Many Famous Novels—Have You Read Yours?'' *https://www.bristolstreet.co.uk/news/car-handbooks-are-longer-than-many-famous-novels--have-you-read-yours/.*

[61] ''Here's Why Nobody Reads Their Car's Owner's Manual'' *https://www.forbes.com/sites/jimgorzelany/2022/04/07/heres-why-nobody-reads-their-cars-owners-manual/?sh=2a76d5d4462d.*

steering wheel vibration used for lane keeping).''

Agency Response

After consideration of the comments, NHTSA is moving forward with the originally proposed requirements for a primary FCW auditory signal and a secondary visual signal, while neither requiring nor prohibiting a supplementary FCW haptic signal. While a few commenters expressed the desire to require a haptic FCW signal, no supporting data were provided. Therefore, NHTSA declines to make a haptic warning signal a requirement. However, NHTSA cautions those interested in implementing supplementary FCW haptic signals to take steps to ensure that the haptic signal used will not be confused with those currently used in association with systems not designed to elicit a forward crash avoidance response, for example, lane-keeping driver assistance features.

b. FCW Auditory Signal Requirements

NHTSA proposed that the FCW auditory signal would be the primary warning modality and asserted criteria to ensure that the FCW would be successful in quickly capturing the driver's attention, directing the driver's attention to the forward roadway, and compelling the driver to quickly apply the brakes. NHTSA proposed that the FCW auditory signal's fundamental frequency be at least 800 Hz and that it include a duty cycle, or percentage of time the sound is present, of 0.25–0.95, and a tempo in the range of 6–12 pulses per second. This final rule also includes FCW requirements that were discussed in the NPRM. Specifically, the FCW auditory signal is required to have a minimum intensity of 15–30 dB above the masked threshold.

Comments

GHSA, Honda, and Rivian supported the proposed standardized FCW auditory signal requirements. Honda stated that the proposed tone, tempo, and frequency would contribute to making this a distinct and recognizable warning, especially if standardized across the fleet. Rivian agreed that a common FCW auditory signal is necessary so that drivers can easily recognize warning conditions across different vehicle makers and models.

Multiple commenters, including the Alliance, Ford, Nissan, Porsche, Toyota, and Volkswagen indicated a preference for more flexibility in the allowed FCW auditory signal characteristics. More specifically, the Alliance and Nissan stated that not defining the required sound level and characteristics is consistent with UNECE Regulation No. 152. Ford recommended that the manufacturer be provided with flexibility to design FCW auditory warning signals. Ford stated that the parameters for an audible alert are often tuned for different vehicle applications or customizable by drivers. Both Porsche and Volkswagen contended that consumers may be used to existing FCW auditory signals used in current vehicles. Volkswagen further stated that allowing flexibility in FCW auditory signal characteristics enables manufacturers to update or adjust the warnings as technologies evolve.

Regarding FCW auditory signal distinguishability, IIHS recommended that NHTSA consider IIHS's method for assessing auditory seat belt reminders to ensure auditory FCWs are easily discerned by drivers beyond ambient levels of sound inside the vehicle.

On the issue of FCW auditory signal deactivation, Hyundai MOBIS encouraged NHTSA to consider permitting the audible warning to be suppressed as long as the FCW visual warning remains illuminated.

Agency Response

The FCW auditory signal minimum intensity requirement was inadvertently left out of the proposed regulatory text, although it was discussed in the preamble of the NPRM. Multiple commenters addressed the topic of FCW auditory signal intensity in their comments. While multiple commenters disagreed with NHTSA's proposed FCW auditory signal criteria, NHTSA's data from 2023 AEB testing also showed that some existing systems already meet some of the FCW proposed requirements. One vehicle, a 2024 Mazda CX–90, met all proposed FCW auditory requirements. Two vehicles met all proposed auditory requirements except the minimum intensity requirement of 15–30 dB above the masked threshold. Two other vehicles met 3 of the 5 FCW auditory signal requirements while the last vehicle met only 2 of the 5 requirements. All six vehicles' FCW auditory signals met the proposed duty cycle requirement and four of the six met the fundamental frequency requirement. Some variety in AEB test vehicles' FCW auditory signals was also seen. FCW auditory signal intensities above the masked threshold spanned a range of 28.8 dBA and five of the six tested vehicles did not meet the proposed intensity requirement. FCW auditory signals fundamental frequencies ranged from 600 to 2000 Hz.

NHTSA believes that auditory signal intensities are especially important for FCW because of the urgency of the crash-imminent situation, the goal of compelling a driver to apply the brakes, and the speed with which action is necessary. Additionally, the minimum sound intensity is supported by research that provides a strong foundation for this requirement. Commenters who did not support the proposed FCW auditory signal requirements provided no data to document the effectiveness of existing FCW auditory signals, nor the purported benefits of permitting vehicle manufacturers to choose their own unique FCW designs. While providing flexibility for design choices that have been proven to increase safety is valuable, providing flexibility that allows for differences related to branding or that just serves to make a model unique does not add safety value.

Regarding Ford's comment expressing interest in the ability to decrease FCW auditory signal intensity when the driver's alertness level is confirmed to be high, NHTSA notes that the proposed requirements provide leeway for manufacturers to implement a less invasive advisory or preliminary alert that would precede the required FCW. It also would not prevent multiple intensities that all meet the minimum requirement in this final rule.

NHTSA disagrees with the suggestion by Hyundai MOBIS to permit the auditory warning to be suppressed as long as the FCW visual warning remains illuminated. As the FCW auditory signal is considered the primary means of warning a potentially inattentive driver, allowing the auditory FCW signal to be suppressed would undercut its important safety function.

After considering the comments, NHTSA has decided to finalize the proposed FCW auditory signal intensity discussed in the preamble of the NPRM in this final rule.

c. FCW Auditory Signal Presentation With Simultaneous Muting of Other In-Vehicle Audio

In the preamble to the NPRM, NHTSA explained its intent to require muting or substantial reduction in volume of other in-vehicle audio (*i.e.,* entertainment and other non-critical audio information) during the presentation of the FCW. This requirement would serve to ensure that the FCW auditory signal is conspicuous to the vehicle operator and detectable at the critical moment at which a crash avoidance response by the driver is needed. However, this intended requirement was inadvertently left out of the proposed regulatory text.

Comments

ASC, MEMA, and ZF supported the muting or reducing other in-vehicle

audio during an audio FCW alert because the FCW alert is the highest priority in the vehicle and should override all other sounds. ASC and MEMA suggested that FCW alert volume should rise with speed to overcome external sounds like wind noise or road noise.

Honda, Porsche and Volkswagen opposed muting of other in-vehicle audio during FCW presentation. Honda stated that, because environmental sound levels can vary drastically, it is unnecessary to require audio muting. Honda cited the lack of a sound level requirement for the FMVSS No. 208 seatbelt warning as rationale for not needing such a requirement for FCW. Porsche and Volkswagen suggested that it is the driver's responsibility to ensure that in-vehicle audio does not interfere with the driving task. Volkswagen cited the requirement of a both a visual and audio warning as justification for not requiring muting of in-vehicle audio. Volkswagen also questioned how to accommodate other mandatory audio signals if these occur simultaneous with the collision warning.

Agency Response

Regarding Honda's comparison to the FMVSS No. 208 auditory warning signal requirement for fastening seatbelts, NHTSA does not believe the two requirements are comparable. The immediate consequences associated with an impending forward crash are not comparable to those associated with vehicle occupants fastening seat belts at the start of a drive.

In response to concerns expressed by Volkswagen and Porsche about addressing multiple simultaneous auditory signals, NHTSA will clarify that the audio required to be muted would be any audio for other than crash avoidance or safety purposes, such as music or other entertainment related audio.

Regarding the assertions by both Porsche and Volkswagen that drivers are responsible for ensuring that in-vehicle audio system use does not interfere with the driver's full attention to the driving task, the situations in which FCW is expected to emit sound are urgent enough that the most attentive driver would need to be able to hear the auditory signal. NHTSA does not believe that attention or inattention is the crux of the issue, though inattention could complicate a driver's response. It is important to ensure that the FCW auditory signal is audible even when sound levels from in-vehicle sources are high.

Although the requirement to mute other in-vehicle audio during the presentation of the FCW was inadvertently left out of the proposed regulatory text, NHTSA is including such a requirement in this final rule. Similar to the issue of auditory intensity, multiple commenters addressed the topic of muting. The requirement will be finalized to require that in-vehicle audio not related to a safety purpose or safety system (*i.e.,* entertainment and other audio content not related to or essential for safe performance of the driving task) must be muted, or reduced in volume to within 5 dB of the masked threshold, during presentation of the FCW auditory signal. This specification will serve to ensure that the amplitude of the FCW auditory signal is at least 10 dB above the masked threshold (MT) to preserve the saliency of the auditory warning.[62]

d. FCW Visual Symbol Requirements

NHTSA proposed that FCW visual signals must use the SAE J2400 (2003–08) symbol.[63] The SAE J2400 symbol relates the idea of an impending frontal crash without depicting a particular forward object and, as such, is readily applicable to both lead vehicle and pedestrian scenarios. The FCW visual signal would be required to be red, as is generally used to communicate a dangerous condition and as recommended by ISO 15623 and SAE J2400 (2003–08). Because the FCW visual signal is intended to be confirmatory for the majority of drivers and because NHTSA-sponsored research [64] has shown that instrument-panel-based crash warnings can draw drivers' eyes downward away from the roadway at a critical time when crash avoidance action may be needed [65] the symbol would be required to be steady burning.

Comments

Multiple commenters voiced support for standardization of FCW characteristics. For example, the Governors Highway Safety Association (GHSA) indicated support for FCW standardization, stating that increased consistency will bolster the safety impact of these features. AAA cited its previous testing experience that some warnings were hardly noticeable relative to visual warnings presented in other vehicles.

Multiple commenters were opposed to specificity included in the proposed FCW requirements. These commenters thought that the state of varied implementation of FCW that exists currently was sufficient. For example, Volkswagen described the proposed warning strategy for AEB as too prescriptive. Volkswagen thought the regulation should specify the warning modes, but leave the implementation up to the manufacturer if the warning is easily perceivable and visually distinguishable from other warnings. Volkswagen thought that variation in FCW strategy across manufacturers would not be a problem because manufacturers explain their warning strategy in their owner's manuals. NADA, Nissan, Mitsubishi, and Porsche also suggested manufacturers have more flexibility to choose the form of visual warning.

The Alliance opined that NHTSA should allow flexibility for manufacturers to select the visual warnings deemed to be most effective in the context of the overall vehicle human-machine interface, which could include ISO or SAE symbols, word-based warnings, or other flashing or steady burning illumination as appropriate. The Alliance stated that NHTSA has not presented data to indicate that any one visual alert type or symbol is any more or less effective than another. Consumer Reports supported standardization but recommended that a word be used rather than a symbol.

Some commenters suggested that the FCW requirements should more closely follow other related standards. Ford recommended establishing FCW requirements similar to existing AEB regulations from Europe,[66] Australia,[67]

[62] Campbell, J.L., Brown. J.L., Graving, J.S., Richard, C.M., Lichty, M.G., Sanquist, T., . . . & Morgan, J.L. (2016, December). Human factors design guidance for driver-vehicle interfaces (Report No. DOT HS 812 360). Washington, DC: National Highway Traffic Safety Administration. ''The amplitude of auditory signals is in the range of 10–30 dB above the masked threshold (MT), with a recommended minimum level of 15 dB above the MT (*e.g.,* [1, 2, 3]). Alternatively, the signal is at least 15 dB above the ambient noise [3].''

[63] SAE J2400 2003–08 (Information report). Human Factors in Forward Collision Warning Systems: Operating Characteristics and User Interface Requirements.

[64] DOT HS 812 191 September 2015, Evaluation of Heavy-Vehicle Crash Warning Interfaces. *https://www.nhtsa.gov/sites/nhtsa.gov/files/812191_evalheavyvehiclecrashwarninterface.pdf.*

[65] ''Evaluation of Forward Collision Warning System Visual Alert Candidates and SAE J2400,'' SAE Paper No. 2009–01–0547, *https://trid.trb.org/view/1430473.*

[66] UN Regulation No 152—Uniform provisions concerning the approval of motor vehicles with regard to the Advanced Emergency Braking System (AEBS) for M1 and N1 vehicles [2020/1597] (OJ L 360 30.10.2020, p. 66, ELI: *http://data.europa.eu/eli/reg/2020/1597/oj*).

[67] Australian Design Rule, Vehicle Standard (Australian Design Rule 98/01—Advanced Emergency Braking for Passenger Vehicles and Light Goods Vehicles) 2021.

and Korea [68] instead of restricting the individual components of the warning. Hyundai opposed the use of SAE J2400 standards, including the symbol. Hyundai believed it was more appropriate to adopt ISO 15623. Porsche's comments seek additional flexibility and alignment with UNECE Regulation No. 152.

Hyundai MOBIS, Toyota, the Alliance, Ford, and Honda, disagreed with the steady burning requirement for the FCW visual signal, expressing support for allowing it to flash. Honda recommended aligning with the specifications of ISO 15008.

Honda supported both visual symbol and word-based FCW options. Honda recommended that NHTSA allow flexibility to continue using already well understood text-based warnings like ''BRAKE!,'' which Honda currently employs, reasoning that a well-designed warning would instruct drivers what to do to avoid a hazard. Rivian also supported allowing the use of the word, ''BRAKE,'' in lieu of an FCW visual symbol.

Agency Response

After careful review of these comments, NHTSA has decided to adopt the proposed standardized FCW visual warning requirements unchanged. While multiple commenters sought flexibility for automakers to use an FCW visual signal of their own choice rather than a standardized signal, no safety data were provided concerning consumers' degree of understanding of the wide variety of existing FCW implementations nor any safety advantages or benefits of not standardizing the visual symbol. The proposed FCW characteristics outlined in the NPRM are based on more than 35 NHTSA research efforts related to crash avoidance warnings or forward collision warnings conducted over the past nearly 30 years. Other research, existing standards (ISO Standards 15623 and 22839), and SAE documents (J3029 and J2400) also were considered as input for the proposed requirements. NHTSA does not view the provided arguments as sufficient to overcome the value of standardization as a means of ensuring consumer familiarity and ensuring the applicability of the chosen symbol to both lead vehicle and pedestrian scenarios.

Data from NHTSA's 2023 AEB testing showed that each of six test vehicle models from different manufacturers used a different FCW visual signal or symbol. Only one model used the ISO FCW symbol. FCW visual symbols that differ by manufacturer and, in some cases across models from the same manufacturer, are likely to lead to confusion among consumers. The observed substantial variety in existing FCW implementations highlights the need for improved consistency of FCW visual symbols to increase efficient comprehension of crash-imminent warnings by vehicle operators and aid them in understanding the reason for their vehicle's (or an unfamiliar rental vehicle's) active crash avoidance intervention. Allowing for individual design choices does not address this important safety consideration.

Such confusion relating to automotive symbol comprehension has also been documented by NHTSA research. Past research conducted by NHTSA to assess comprehension of vehicle symbols including the ISO tire pressure, ISO tire failure, and ISO engine symbols showed that while 95 percent of subjects correctly identified the engine symbol, recognition percentages for the ISO tire pressure and tire failure icons were the lowest of the 16 icons tested, 37.5 percent and 25 percent, respectively.'' [69] Research by industry published in a 2004 SAE paper focused on comprehension testing of active safety symbols and assessed the ISO FCW symbol and the SAE J2400 FCW symbol to assess their ability to communicate the idea, ''Warning: You may be about to crash into a car in front of you.'' Results of that research showed the ISO FCW symbol to have 45 percent ''high comprehension'' and the SAE J2400 symbol to have 23 percent high comprehension. However, while high comprehension was noted for the lead vehicle crash scenario, NHTSA is not aware of any data supporting effectiveness of the ISO FCW symbol for communicating the idea of an impending forward pedestrian crash.'' [70]

Consumer Reports ''Guide to ADAS'' states that ''CR's most recent survey data shows that industry-wide, only 48% of owners of vehicles equipped with FCW say they understand how it works.'' [71]

NHTSA believes that improved consistency of FCW visual symbols is important to increase efficient comprehension of crash-imminent warnings.

NHTSA acknowledges the research by IIHS showing crash reduction benefits from some existing FCW designs. IIHS research results found that some automakers' FCW designs were associated with higher crash reductions than others. However, this research did not evaluate FCW characteristics by automaker or by model for vehicle models it studied and whether such characteristics may have contributed to FCW effectiveness differences, so care should be taken when drawing conclusions. Regardless, the IIHS studies have shown some existing FCW in light vehicles FCW systems are effective for preventing rear-end crashes, research does not support an argument against taking other measures to increase FCW effectiveness. It is likely that increasing the consistency of FCW characteristics and standardization of the primary warning signals across vehicles and models will lead to benefits beyond those documented to date due to increased driver understanding of the meaning of FCW signals.

The agency disagrees with Volkswagen's comment that explanations in the owner's manual adequately inform consumers about manufacturer-specific FCW signals. As noted previously, a British study found that only 29% of motorists surveyed had read their car handbook in full.[72] That same study examined owner's manual word counts and estimated that the time required to read some of the longest would take up to 12 hours. An April 2022 Forbes article states that ''the average new-vehicle's owners' manuals, which, concurrent with the complexity of contemporary cars, have become imposingly thick and mind-numbing tomes of what should be essential information . . . remain unread in their respective models' gloveboxes.'' [73] With these concerns in mind, NHTSA does not believe that owner's manual information is an acceptable substitute for standardization of this important safety functionality across all vehicles.

[68] Korean Motor Vehicle Safety Standard (KMVSS) Article 15–3, ''Advanced Emergency Braking Systems (AEBS).''

[69] Mazzae, E.N. and Ranney, T.A. (2001). ''Development of an Automotive Icon for Indication of Significant Tire Underinflation.'' Article in Proceedings of the Human Factors and Ergonomics Society Annual Meeting · October 2001. DOI: 10.1177/154193120104502317.

[70] Campbell, John & Hoffmeister, David & Kiefer, Raymond & Selke, Daniel & Green, Paul & Richman, Joel. (2004). Comprehension Testing of Active Safety Symbols. 10.4271/2004–01–0450.

[71] Consumer Reports' Guide to ADAS Usability: Consumer insights on understanding, use, and satisfaction of ADAS December 2022. *https://data.consumerreports.org/wp-content/uploads/2021/09/consumer-reports-active-driving-assistance-systems-ux-guide-revised-december-09-2022.pdf.*

[72] ''Car Handbooks Are Longer Than Many Famous Novels—Have You Read Yours?'' *https://www.bristolstreet.co.uk/news/car-handbooks-are-longer-than-many-famous-novels—have-you-read-yours/.*

[73] ''Here's Why Nobody Reads Their Car's Owner's Manual'' *https://www.forbes.com/sites/jimgorzelany/2022/04/07/heres-why-nobody-reads-their-cars-owners-manual/?sh=2a76d5d4462d.*

Finally, as for the use of words instead of a symbol, as noted in the NPRM, word-based FCW visual warnings are used by some U.S. vehicle models including, ''BRAKE!,'' ''BRAKE,'' and ''STOP!''. SAE J2400 also includes a word-based visual warning recommendation consisting of the word, ''WARNING.'' With regard to this existing use of word-based FCW visual warnings in some models, research by Consumer Reports noted in its online ''Guide to forward collision warning'' found that for some models, visual warning word use was found to be confusing to some drivers surveyed. Specifically, survey respondents reported a common complaint that ''their vehicle would issue a visual ''BRAKE'' alert on the dash, but it wouldn't bring the car to a stop.'' [74] While NHTSA does find merit in the rationale for using an effective word-based visual warning for FCW purposes, we have decided in favor of the value of consistency across U.S. vehicles to promote consumer recognition of a dedicated FCW symbol. This symbol-based strategy for the FCW visual signal follows is consistent with the strategies of ISO 15623 and SAE J2400 (2003–08).

NHTSA notes, however, that this requirement does not preclude the use of a word-based warning that supplements the required FCW symbol presentation. In that event, NHTSA agrees with Honda and Consumer Reports that the word, ''BRAKE!'', including the exclamation point, is likely the best choice for effective communication to the driver the need for them to apply the brakes. NHTSA believes, as has been suggested by Consumer Reports, that there is a tendency for drivers to interpret some words used as warnings as describing an action being performed by the vehicle, rather than a command to the driver. To avoid such confusion by the driver, NHTSA recommends that manufacturers wishing to complement the FCW symbol with a word-based warning use, ''BRAKE!'' to aid in drivers interpreting the word as an instruction.

Finally, with respect to the steady-burning requirement, NHTSA does not agree with commenters recommending that the FCW visual warning be allowed to flash. As the FCW visual signal is intended to be secondary to the FCW auditory signal, allowing the symbol to flash in an attempt to draw the drivers' attention could actually draw the drivers' gaze downward to the instrument panel rather than to the forward roadway at a critical time for the driver to initiate a crash avoidance response.

After evaluation of the comments, the agency has determined to retain the proposal requirement for the visual symbol from SAE J2400 (2003–08), ''Human Factors in Forward Collision Warning Systems: Operating Characteristics and User Interface Requirements'' (Information report), to communicate the idea of an impending frontal crash without depicting a particular forward object. With no comments opposed to requiring the FCW visual signal to be presented using the color red, NHTSA is also finalizing that requirement as proposed and clarifying that it will apply to the required FCW symbol and any manufacturer-chosen words to accompany the required symbol.

e. FCW Visual Signal Location Requirements

The agency proposed that the FCW visual signal be presented within a 10-degree cone of the driver's forward line of sight.[75] This requirement is based on SAE J2400, ''Human Factors in Forward Collision Warning Systems: Operating Characteristics and User Interface Requirements,'' paragraph 4.1.14. This FCW visual signal location guidance is also consistent with ISO 15623, which states that the FCW visual signal shall be presented in the ''main glance direction.'' Multiple research studies provide support for a visual warning location close to the driver's forward line of sight. NHTSA-sponsored research also supports this requirement, showing that instrument-panel-based crash warnings can draw drivers' eyes downward away from the roadway at a critical time when crash avoidance action may be needed.[76] Industry-sponsored research published in 2009 also indicates that an FCW visual signal presented in the instrument panel can slow driver response.[77] The 10-degree requirement would also increase the likelihood of FCW visual signal detection by hearing-impaired drivers.

Comments

Consumer Reports and AAA supported the proposed requirement that the FCW visual signal be presented in a location within a 10-degree cone of the driver's forward line of sight. In contrast, multiple commenters opposed the 10-degree cone requirement, some believing that the requirement could only be met using a head-up display. A majority of commenters who addressed this point requested that NHTSA consider expanding the 10-degree cone of the driver's line of sight requirement for FCW visual signal location.

FCA, Hyundai, Nissan, NADA, Rivian, and Volkswagen opposed the 10-degree cone requirement. The Alliance disagrees that the SAE J2400 information report provides adequate justification for the 10-degree requirement.

FCA thought the proposed requirement was impracticable. Rivian recommended that the FCW visual signal be presented on the top location of the driver instrument panel, in the instrument panel, or in a head-up display unless NHTSA can demonstrate that the data indicates that one location is clearly superior for driver perception. Toyota requested that the cone size be expanded to allow for suitable placement of the visual alert in areas such as the meter cluster or multi-information display, which would still be clearly visible in front of the driver.

Porsche recommended that NHTSA consider replacing the 10-degree with an allowance of up to 30 degrees, arguing that this would facilitate the use of long-established visual warning locations which it viewed as sufficient to provide the necessary cues. Multiple commenters, including Mitsubishi, the Alliance, and Honda, recommended use of a 60-degree cone requirement. Mitsubishi explained that the 60-degree value is based on a book chapter titled, Visual Fields, by R.H. Spector, et al., which states the vertical viewing angle of humans to be 60 degrees.

Agency Response

While many current vehicle models present an FCW visual signal within the instrument panel, drawing a driver's eyes downward away from the roadway in front of them to the instrument panel during a forward crash-imminent situation is likely to have a negative impact on the effectiveness of the driver's response to the FCW. NHTSA's research indicates that a visual FCW signal presented in the instrument panel can draw drivers' eye gaze downward away from the forward roadway and slow driver response to a forward crash-

[74] ''Guide to forward collision warning: How FCW helps drivers avoid accidents.'' Consumer Reports. *https://www.consumerreports.org/carsafety/forward-collision-warning-guide/*. Accessed April 2022.

[75] Line of sight based on the forward-looking eye midpoint (Mf) as described in FMVSS No. 111, ''Rear visibility,'' S14.1.5.

[76] DOT HS 812 191 September 2015, Evaluation of Heavy-Vehicle Crash Warning Interfaces. *https://www.nhtsa.gov/sites/nhtsa.gov/files/812191_evalheavyvehiclecrashwarninterface.pdf.*

[77] ''Evaluation of Forward Collision Warning System Visual Alert Candidates and SAE J2400,'' SAE Paper No. 2009–01–0547, *https://trid.trb.org/view/1430473.*

imminent event.[78] Further, Industry-sponsored research published in 2009 also indicates that an FCW visual signal presented in the instrument panel can slow driver response.[79]

Mitsubishi highlighted content from ''Visual Fields,'' by R.H. Spector, et.al that states the vertical viewing angle of humans to be 60 degrees.[80] Specter's chapter specifically states that ''a normal visual field is an island of vision measuring 90 degrees temporally to central fixation, 50 degrees superiorly and nasally, and 60 degrees inferiorly.'' Mitsubishi contended that if the FCW visual warning is displayed within this range, the driver will be able to recognize it. However, the referenced Spector visual field information relates to average humans' ability see objects presented before them and not specifically to drivers' ability to detect and quickly respond to an FCW visual signal within the potentially cluttered visual scene of a driver's-view perspective. Research sponsored by NHTSA and industry, respectively, has shown that instrument panel based visual crash warnings can draw drivers' eyes downward away from the roadway at a critical time when crash avoidance action may be needed and that an FCW visual signal presented in the instrument panel can slow driver response.[81] [82] Comparison to other warnings is not apt because other most other warnings do not require as immediate of a response as FCW.

As the text of SAE J2400 states, locating the FCW visual signal within a 10-degree cone could be accomplished in a top-of-dashboard location, NHTSA did not intend to require presentation of the FCW visual signal only via head-up display. To evaluate the potential difficulties associated with attempting to meet this FCW visual symbol location requirement, NHTSA gathered additional information regarding what visual angle about the driver's forward line of sight could be used to locate the FCW visual signal near the driver's forward line of sight, such as within the upper center portion of the instrument panel, without requiring substantial redesign of vehicles' instrument panels or dashboards, or require a head-up display.

NHTSA gathered information regarding the driver's visual angle when looking at the instrument panel for a set of 10 light vehicles. Eight of the vehicles were model year 2022, one was from the 2021 model year, and one was from model year 2023. Vehicle makes examined spanned a wide range of manufacturers including Chevrolet, Ford, Honda, Hyundai, Jeep, Nissan, RAM Subaru, Toyota, and Volkswagen. The vehicles examined also spanned a range of vehicle sizes including two large pickup trucks.

NHTSA used a coordinate measuring machine to record within a single coordinate system the locations of the upper and lower extents of the active display area of each vehicle's instrument panel, as well as the left and right extents of the instrument panel. These points were used to locate the geometric center of the instrument panel. The eye midpoint location for a properly seated 50th percentile male driver was also located using an H-point machine and recorded. The 50th percentile male driver size was used to represent the midpoint of the range of possible driver eye midpoint locations across all driver sizes. This full set of coordinate data was used to calculate visual angles between the eye midpoint and each of the center and upper and lower extents of the vehicles' instrument panels at their horizontal center. The plot below depicts visual angle calculation results for the instrument panel central upper edge, center point, and central lower edge for a 50th male driver's point of view.

[78] DOT HS 812 191 September 2015, Evaluation of Heavy-Vehicle Crash Warning Interfaces. *https://www.nhtsa.gov/sites/nhtsa.gov/files/812191_evalheavyvehiclecrashwarninterface.pdf.*

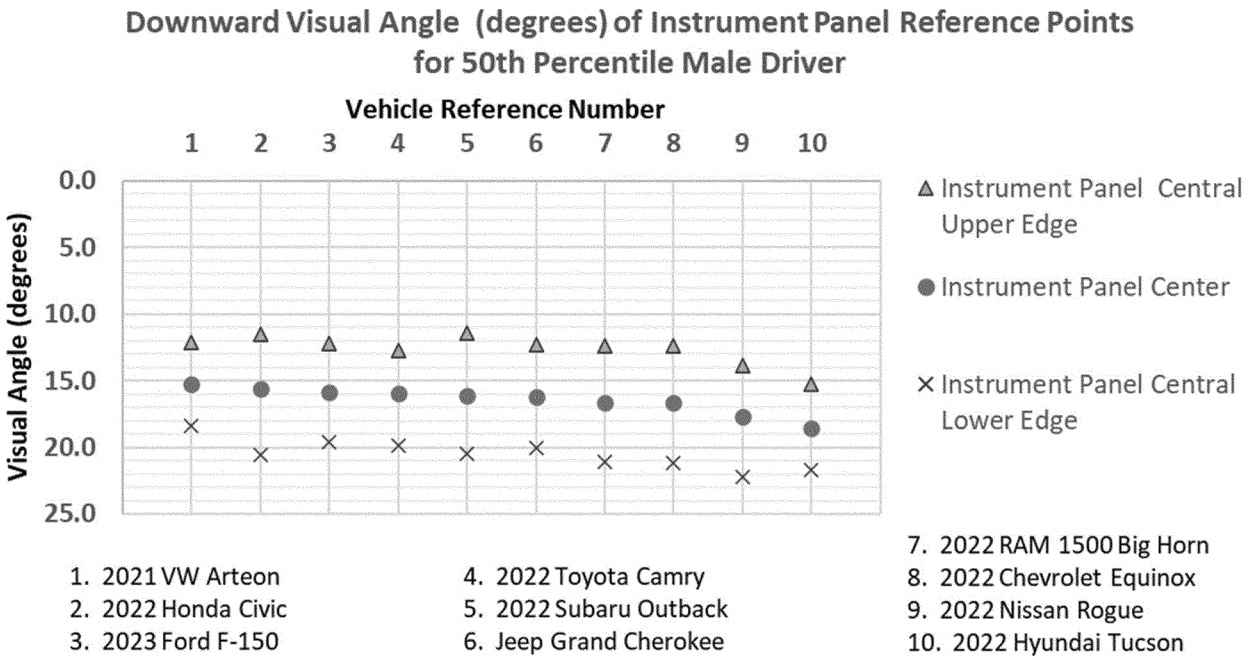
[79] ''Evaluation of Forward Collision Warning System Visual Alert Candidates and SAE J2400,'' SAE Paper No. 2009–01–0547, *https://trid.trb.org/view/1430473.*

[80] Spector RH. Visual Fields. In: Walker HK, Hall WD, Hurst JW, editors. Clinical Methods: The History, Physical, and Laboratory Examinations. 3rd ed. Boston: Butterworths; 1990. Chapter 116. PMID: 21250064.

[81] DOT HS 812 191 September 2015, Evaluation of Heavy-Vehicle Crash Warning Interfaces. *https://www.nhtsa.gov/sites/nhtsa.gov/files/812191_evalheavyvehiclecrashwarninterface.pdf.*

[82] ''Evaluation of Forward Collision Warning System Visual Alert Candidates and SAE J2400,'' SAE Paper No. 2009–01–0547, *https://trid.trb.org/view/1430473.*

Figure 1:



Visual angle values for the instrument panel center point for these vehicles were found to range from 15.7 to 18.5 degrees. Nine of the ten vehicles were found to have instrument panel center locations that reside within 18 degrees downward of the driver's forward horizontal line of sight. Based on these data, NHTSA believes that revising the FCW visual symbol location 10-degree requirement to an 18-degree vertical angle would permit the large majority of current vehicle designs to display a telltale-sized or larger FCW visual symbol in the upper half of the instrument panel without any structural redesign or necessity of using a head-up display. Therefore, NHTSA has decided to expand the vertical angle to 18 degrees while retaining the 10-degree horizontal angle. The 10-degree value is being retained for the horizontal angle to preserve the FCW symbol's presentation at the center of the driver's forward field of view to maximize its perceptibility.

2. AEB Requirement

a. AEB Deactivation

NHTSA discussed the issue of AEB deactivation in various circumstances, and the various ways it might become deactivated (*i.e.,* manually or automatically). NHTSA used both ''disablement'' and ''deactivation'' in the proposal, intending that those terms mean the same thing. The NPRM proposed prohibiting manual AEB system deactivation at any speed above the proposed 10 km/h minimum speed threshold for AEB system operation. NHTSA sought comment on this and whether the agency should permit manual deactivation similar to that permitted for ESC systems in FMVSS No. 126. NHTSA also sought comment on the appropriate performance requirements if the standard permitted installation of a manually operated deactivation switch.

Regarding automatic deactivation, NHTSA stated that it anticipated driving situations in which AEB activation may not increase safety and in some rare cases may increase risk. For instance, an AEB system where sensors have been compromised because of misalignment, frayed wiring, or other partial failure, could provide the perception system with incomplete information that is misinterpreted and causes a dangerous vehicle maneuver. In instances where a light vehicle is towing a trailer with no independent brakes, or with brakes that do not include stability control functions, emergency braking may cause jack-knifing, or other dangerous outcomes. In the proposal, NHTSA stated that it was considering restricting the automatic deactivation of the AEB system generally and sought comment on providing a list of situations in which the vehicle is permitted to automatically deactivate the AEB or otherwise restrict braking authority granted to the AEB system.

In addition to these situations, NHTSA requested comment on allowing the AEB system to be placed in a nonfunctioning mode whenever the vehicle is in 4-wheel drive low or the ESC is turned off, and whenever equipment is attached to the vehicle that might interfere with the AEB system's sensors or perception system, such as a snowplow. NHTSA requested comment on the permissibility of automatic deactivation of the AEB system and under which situations the regulation should explicitly permit automatic deactivation of the AEB system.

Comments

Several commenters discussed AEB deactivation. The City of Philadelphia, the Richmond Ambulance Authority, DRIVE SMART Virginia, the National Association of City Transportation Officials (NACTO), Advocates for Highway and Auto Safety (Advocates), the Nashville Department of Transportation and Multimodal Infrastructure, and the City of Houston supported the proposed requirement to prevent AEB deactivation. In general, they stated that allowing system deactivation would diminish safety benefits.

In contrast, many commenters stated that AEB deactivation should be allowed. For example, ASC, ZF, MEMA, NADA, Mitsubishi, Porsche, Aptiv and Volkswagen suggested that the agency should follow the specific deactivation criteria under UNECE Regulation No. 152. That regulation requires at least

two deliberate actions to deactivate the AEB system, and the system must default back to ''on'' after each ignition cycle.[83] Toyota, Porsche, and Hyundai stated that manual deactivation for AEB systems should be similar to what is allowed for ESC systems in FMVSS No. 126. Rivian stated that manual deactivation should be allowed via either a software or hardware switch.

Advocates opposed allowing deactivation of AEB systems, but they provided some suggestions for NHTSA if deactivation were allowed in narrowly tailored instances for specific applications with strong justification and supporting data. Advocates stated that any conditions allowed for automatic deactivation must not enable a means to intentionally deactivate the AEB system and suggest that any deactivation should trigger the malfunction telltale and be recorded as part of a data recording requirement. If NHTSA were to allow manual AEB deactivation, Advocates thought the process should require multiple steps while the vehicle is not moving and require drivers to engage in a deliberate and significant effort (*i.e.* a driver should not be able to disable AEB by pressing a single button). Advocates aligned with other commenters in suggesting that if any AEB deactivation occur, the system should default back to ''on'' at any new ignition cycle.

The Alliance, Honda, NADA, Porsche, and Volkswagen suggested that the agency should allow manual deactivation to mitigate consumer dissatisfaction. Honda and NADA also stated that not allowing deactivation may lead to substantially higher false positive rates, while AAA stated that allowing for automatic or manual deactivation could increase consumer acceptance and minimize the perception that the systems are overbearing. NADA also stated that AEB false positives are a significant source of consumer complaints about AEB systems and that only 59 percent of respondents to a Consumer Reports survey indicated that they were satisfied with their AEB systems. The Alliance stated that in many cases, the circumstances warranting AEB deactivation are already described in vehicle owner's manuals or other information sources, and that it supports the continuation of describing such circumstances to the user.

ASC stated that for ADAS-equipped vehicles where the primary operating responsibility belongs to the driver, AEB is an assist function and the driver should be able to deactivate the AEB system if required. ASC also stated that under extreme operating or environmental conditions, the AEB system may be outside its operating design domain and should automatically deactivate (temporarily) and that in some situations such as testing, or service, the AEB system should be able to be deactivated.

SEMA, Ford, The Alliance, Rivian, Volkswagen, and HATCI suggested that there are likely several circumstances where deactivation of the system may be needed to ensure a safe vehicle operation, including track use, off-road use, and car washes. Some specific examples suggested by commenters include the use of chains on tires for traction, towing, four-wheel drive, low traction driving scenarios, and off-roading. SEMA and Mitsubishi stated that on a vehicle towing a trailer without an independent brake system, AEB activation may cause jack-knifing or other dangerous conditions. MEMA stated that drivers of many existing vehicles can currently disable their AEB system in cases where the AEB system is predictably, but incorrectly, triggered by objects or structures.

NTEA stated that there is a need to be able to deactivate AEB when certain vocational equipment is attached in frontal areas where it intrudes into the field-of-view of an AEB system. NTEA stated that final stage manufacturers and alterers are not currently (nor foreseeably in the future) able to move/reinstall/recalibrate these systems to accommodate vocational upfits that can be in direct conflict with how these systems need to function. NTEA uses snowplows as an example of a vehicle equipment for which sensor relocation cannot accommodate AEB. NTEA stated, as an example of how provisions for deactivation could be included in the requirement, that one vehicle manufacturer has previously created a method to detect the presence of a plow blade in their electrical architecture, so that when the blade is attached, AEB is deactivated. AEB functionality resumes when the blade hardware is removed. NTEA provided examples of other front-mounted equipment such as winches, sirens and push bumpers on emergency vehicles that could cause unintended consequences with the system reaction of AEB. Further, NTEA identified operational aspects of emergency and first responder vehicles that merit more consideration for AEB deactivation.

The Alliance and Porsche stated that NHTSA should provide manufacturers with the ability to define automatic deactivation criteria. While Volkswagen stated that NHTSA should provide a list of situations where automatic deactivation is allowed it stated that this list should not be mandatory and joined the Alliance and Porsche in stating that OEM's should establish the situations where the AEB system is permitted to automatically deactivate, or otherwise restrict braking authority granted to the AEB system. HATCI did not specifically comment on the list of situations, but stated that allowing manual deactivation would provide affordances for unforeseen scenarios that industry and NHTSA have not yet contemplated which would help futureproof against situations that may not exist today. The Alliance stated that this approach introduces additional complexity in terms of demonstrating compliance with the standard. Porsche stated that providing a not ''overly intrusive'' deactivation warning message would be appropriate and that the range of situations in which the systems would be automatically deactivated be infrequent and of limited duration.

Finally, the Alliance also addressed whether the deactivation of ESC may cause deactivation of AEB. While not encouraged, a driver seeking to disable AEB may be left with no option but to turn both AEB and ESC systems off under NHTSA's proposal, reducing potential safety benefits from having the ESC system remain active.

Agency Response

In this final rule, NHTSA does not allow for vehicles to be equipped with a manual control whose sole functionality is the deactivation of the AEB system. NHTSA agrees with the commenters who noted concerns about diminishing the safety benefits of this rule. Harmonization alone is an insufficient justification for allowing a control to deactivate the AEB system. Commenters have not explained why there is a safety need of a dedicated deactivation control or why a dedicated deactivation control would not diminish the safety benefits of AEB. The agency also disagrees with ASC's assertion that AEB is an ''assist function,'' and even if true, that such a description would serve as a justification for allowing a manual deactivation control.

NHTSA does not agree that any theoretical consumer dissatisfaction is one of the circumstances that justify allowing manual deactivation. AEB systems have been available on vehicles for many years. It is not reasonable to assume that there will be consumer acceptance issues due to the requirements of this final rule.

[83] UN Regulation No 152—Uniform provisions concerning the approval of motor vehicles with regard to the Advanced Emergency Braking System (AEBS) for M1 and N1 vehicles [2020/1597] (OJ L 360 30.10.2020, p. 66, ELI: *http://data.europa.eu/eli/reg/2020/1597/oj*).

NHTSA is not persuaded by comments that suggest that not permitting deactivation would lead to substantially higher false positive rates. NHTSA recognizes that AEB false positives are a source of consumer complaints, but NHTSA does not believe AEB deactivation is the solution to the engineering challenges manufacturers with lower performing systems might face in meeting this rule's requirements.

That said, NHTSA recognizes that there are certain circumstances where deactivation may be appropriate, and the commenters raise several situations where NHTSA believes automatic deactivation would be the best approach. Examples of such a scenario include when a trailer is being towed, or when a snowplow is attached to a pickup truck. AEB activation while towing a trailer may be unsafe if the trailer does not have brakes. A snowplow may interfere with the sensing capabilities of the AEB system. In such cases, NHTSA expects that the manufacturer would automatically disable AEB functionality when interference with the sensing capabilities occurs. Using the example of towing, NHTSA expects that the manufacturer would design AEB to scan for towing connections and automatically disable AEB if it registers any.

NHTSA agrees that it is important for the AEB system to default back to ''on'' after each ignition cycle, except in one circumstance—in a low-range four-wheel drive configuration selected by the driver on the previous ignition cycle that is designed for low-speed, off-road driving. In that situation, NHTSA believes that reverting to the manufacturer's original default AEB setting would not be necessary. There is a similar exception for the ESC Off control.

NHTSA also agrees with the Advocates that any deactivation should trigger the malfunction telltale because consistent illumination is important to remind drivers that safety equipment (*i.e.,* AEB) is not functioning as the driver expects. Should the OEM design its systems in a way where the AEB system would automatically deactivate when the system detects that it cannot function properly (*i.e.,* change performance in a way that takes the AEB system out of compliance with the requirements of the standard), then the driver must be alerted of this performance issue through a telltale. This applies to partial or full disablement of the system.

NHTSA does not agree with the Alliance that restricting the installation of an ''AEB off'' control leaves a driver seeking to disable AEB with no option but to turn both AEB and ESC systems off. First, it is up to the manufacturer to decide if AEB is automatically turned off when ESC is turned off. Second, while it is not restricted by the FMVSS, it is the manufacturer's choice to install an ESC off switch. Finally, the agency asserts that if a driver does use the ESC off control for the purpose of turning off AEB, the restrictions included in this final rule limit the potential safety impacts particularly once the vehicle's ignition is turned off because AEB is required to turn back on with each ignition cycle, except when using a low-range four-wheel drive configuration.

While NHTSA understands commenters' concerns about emergency vehicles, the Agency notes that flexibilities already exist for these vehicles, and we anticipate those flexibilities would be appropriate and sufficient to address these concerns. There are a number of ways that owners, and purchasers of emergency vehicles for official purposes, could modify their vehicles to fit the unique needs of emergency responders. Currently, manufacturers have the ability to sell upfit packages that provide the means, and instructions (upfit guides), for an emergency responder to interact with various vehicle features, including mandated safety features. A common example of these modifications involves the modification of lighting equipment and the activation of patterns which are not compliant with FMVSS No.108. While a vehicle manufacturer cannot manufacture a vehicle for sale with such lighting and activation patterns that fail to comply with FMVSS No. 108, Lamps, reflective devices, and associated equipment, an emergency responder, as the owner of a vehicle, is not prohibited from making modifications to the vehicle.[84] In addition, this final rule allows for the deactivation of AEB when ancillary systems that may affect AEB performance are activated.

In summary, NHTSA agrees with those commenters expressing opposition to broad inclusion of an on-off switch. The agency believes, as do those commenters, that the lifesaving benefits would be significantly compromised. However, some commenters noted that certain vehicles are used in unusual environments or for unique purposes, and their operation might be hampered by an AEB system that cannot be deactivated. The agency has not included on-off AEB functionality for emergency vehicles, as a broad group, as these purpose-built vehicles already have flexibilities. However, the agency believes that one other situation is appropriate for inclusion of on-off functionality—vehicles used by law enforcement.

Law enforcement has unique needs that often necessitate some differences in the configuration or functionality of their motor vehicles. The motor vehicles they purchase may be purpose-built police vehicles or unaltered vehicles available to the general public. In either case, law enforcement has a critical need to deactivate AEB when such vehicles are used in intervention maneuvers to disable a suspect's vehicle or in security escorts and processions driving in tight formation. For this reason, this final rule provides a limited exception that allows the manufacture, or the modification after sale, of vehicles that include the ability to activate and deactivate AEB for vehicles owned by law enforcement agencies.[85] Manufacturers should work to directly provide an on-off capability for verified law-enforcement-owned vehicles or make it as easy as possible for a third party to do so on behalf of law enforcement, with appropriate security safeguards, and NHTSA is committed to actively facilitating this process. Should manufacturers fail to address this important need, NHTSA may consider taking additional regulatory action. NHTSA anticipates that law enforcement vehicles resold to other than law enforcement entities will be restored to their original condition (*i.e.,* by disabling the on-off capability).

NTEA's comment requests that NHTSA consider adding regulatory compliance pathways for upfitters. NHTSA understands NTEA's concern regarding glass replacement and the impact that has on FCW/AEB sensors. As AEB is not a new system, this is not a new issue for glass replacement upfitters. The agency is aware of glass replacement upfitters that already work with manufacturers to ensure proper sensor calibration. It is not expected that the requirements of this final rulemaking will affect their ability to continue to collaborate as they have been. NHTSA also expects that manufacturers might provide for automatic deactivation for vocationally

[84] In the absence of an AEB mandate, some OEMs currently facilitate deactivation for emergency responders; for example ''Available PreCollision Assist With Pedestrian Detection— . . . For unique law-enforcement demands, a switch allows the feature to be temporarily disabled.'' *https://www.ford.com/police-vehicles/hybrid-utility/,* Accessed March 7th, 2024 at 10:20 a.m.

[85] The agency does not have a precise estimate of the number of vehicles that may be affected by this flexibility, but notes that, when considered as part of the entire fleet, this effect is likely to be de minimis.

specific equipment when it is in use, such as the snowplow example NTEA provides in its comment.

As for the equipment installed for vocational vehicles, NHTSA expects upfitters to avoid installing equipment that would result in AEB no longer working (or malfunctioning). NHTSA expects that in rare cases where no engineering solution may exist such as with snowplows, that upfitters would leave final installation of this equipment to the vehicle owners to avoid making inoperative required safety equipment. In such situations, NHTSA expects that the malfunction indicator would illuminate as a constant reminder to the driver that AEB is not working. As discussed in other sections, NHTSA believes that this consistent illumination is important to remind drivers that important safety equipment (*i.e.,* AEB) is not functioning as the driver expects.

b. Aftermarket Modifications

SEMA stated that while the proposed rule applies to motor vehicle manufacturers and alterers of new passenger cars and light trucks, it does not specify how aftermarket vehicle modifications and alterations may impact AEB systems. SEMA stated that they seek guidance from NHTSA on implementing FMVSS for AEB and PAEB and the legal obligations of SEMA members who produce, install, or sell aftermarket parts, as well manufacturers, installers, retailers, distributors, and independent repair shops regarding the ''tampering/make inoperative'' provision (49 U.S.C. 30122).

NHTSA notes that SEMA's comment invokes two separate provisions of the Safety Act because the situations of alterers and repair businesses are different. NHTSA has issued several interpretations of the obligations of both alterers and repair businesses, and the agency summarizes those key points here.[86]

An ''alterer'' is defined as a person who alters by addition, substitution, or removal of components (other than readily attachable components) a certified vehicle before the first purchase of the vehicle other than for resale.[87] The Safety Act and NHTSA's regulations require vehicle manufacturers certify that their vehicles comply with all applicable FMVSSs (49 U.S.C. 30112; 49 CFR part 567). NHTSA's regulations at 49 CFR 567.7 require the alterer to ensure that the vehicle, as altered, conforms to the FMVSSs affected by the alteration(s) and to certify to that effect in accordance with the same section. Alterers make this certification by affixing a permanent label to the altered vehicle identifying the alterer and the date of alteration.

In contrast, a vehicle repair business is defined as a person holding itself out to the public to repair for compensation a motor vehicle or motor vehicle equipment. Repair businesses usually work on vehicles after the time of first sale, which means that instead of complying with the certification requirements like a manufacturer or alterer, a repair business must ensure that it does not violate the Safety Act's make inoperative prohibition. The Safety Act states that a vehicle manufacturer, distributor, dealer, rental company or repair business is prohibited from knowingly making inoperative any part of a device or element of design installed in or on a motor vehicle that complies with an applicable FMVSS.[88] An entity does not need to have actual knowledge that a device or element of design would be made inoperative by the entity's modification in order for that modification to violate section 30122.[89]

Additionally, section 30122 does not require repair shops to restore safety systems damaged in a collision to a new or pre-crash condition.[90] Instead, under section 30122, when any repair to a vehicle is completed, the vehicle must be returned to the customer with the safety systems capable of functioning at least as well as they were able to when the vehicle was received by the repair shop.[91]

Given the information above, NHTSA concludes the two types of entities about which SEMA is concerned both have an obligation to prevent a noncompliance with the FMVSS created by this final rule. Since NHTSA is establishing a new FMVSS with this final rule, the same rules of certification and make inoperative will apply, except for narrow circumstances for law enforcement-owned vehicles.

NHTSA is aware that many law enforcement vehicles are modified after purchase to meet the unique needs of law enforcement. Sometimes this work is completed by in-house entities, and other times, this work may be contracted out to third parties. If those third parties are the entities listed in 49 U.S.C. 30122, they are prohibited from making inoperative any system or element of design that is in compliance with a FMVSS, including this new FMVSS. To ensure that law enforcement are able to modify their vehicles to fit their unique needs, and to ensure that third-party repair businesses are capable of assisting them, NHTSA has added a make inoperative exemption in 49 CFR part 595 that permits manufacturers, dealers,and motor vehicle repair businesses to modify a vehicle owners by a law enforcement agency to provide a means to temporarily deactivate an AEB system. This addition is complementary to the additional text added in S5.4.2.1 and discussed in the proceeding section.

c. No-Contact Requirement for Lead Vehicle AEB

The proposed performance criterion for all AEB tests involving a lead vehicle is full collision avoidance, meaning the subject vehicle must not contact the lead vehicle.

NHTSA requested comment on two alternatives to a no-contact requirement for the lead vehicle performance test requirements. The first alternative would be to permit low speed contact in NHTSA's on-track testing. The agency requested comment on the appropriateness of such a requirement, any factors to consider surrounding such a performance level, and what the appropriate reduction in speed or maximum impact speed should be. The other alternative discussed in the proposed rule was a requirement that permits the vehicle to use multiple runs to achieve the performance test requirements. This alternative is discussed in the ''Permissibility of Failure'' section.

Comments

In response to the NPRM, the IIHS, the Advocates, NTSB, AAA, Adasky, and Luminar, expressed support for the full collision avoidance (*i.e.,* no-contact) requirement in all proposed AEB tests. IIHS stated that their evaluations of existing AEB systems indicated that some current systems are completely avoiding collisions at the highest speeds IIHS has tested, which is 70 km/h. Advocates stated that the vehicles are

[86] Letter to Antonio Salvetti (Dec. 29, 1994) *https://www.nhtsa.gov/interpretations/10425#:~:text=An%20%22alterer%22%20is%20one%20who,such%20as%20painting%2C%20or%20by;* Letter to Alan Nappier, Earl Stewart Toyota (Apr 17, 2015). *https://www.nhtsa.gov/interpretations/30122-make-inoperative-alan-nappier-april-14.*

[87] 49 CFR 567.3.

[88] 49 U.S.C. 30122.

[89] Letter to Alan Nappier, Earl Stewart Toyota (Apr. 17, 2015), *https://www.nhtsa.gov/interpretations/30122-make-inoperative-alan-nappier-april-14.*

[90] *See, e.g., http://isearch.nhtsa.gov/aiam/aiam4681.html,* letter to Linda L. Conrad, January 19, 1990.

[91] Nonetheless, NHTSA strongly encourages repair shops to restore functionality to safety systems to ensure that the vehicles will continue to provide crash protection for occupants during the life of the vehicle.

tested under nearly ideal conditions and, by requiring a no-contact condition for success, the benefits of the system will be stronger under less-than-ideal conditions in the real world. NTSB and AAA stated that the no-contact requirement is consistent with the need for safety, and potentially necessary to ensure test repeatability. Luminar stated that they were concerned that regulating some degree of contact in these scenarios presents significant concerns for test efficiency, integrity and cost related to compliance. Luminar stated that the no-contact performance is within the capability of existing technology.

Several commenters, including the Alliance, Honda, FCA, Nissan, Volkswagen, SEMA, and MEMA stated that the proposed no-contact requirement in lead vehicle AEB tests is not practicable at the proposed test speeds. Many of these commenters suggested a hybrid approach of collision avoidance at lower speeds and speed reduction at higher speeds. Multiple commenters stated that the proposed test speeds will require earlier intervention by AEB systems to meet the ''no-contact'' requirement, which they state will cause various unintended consequences, such as false positives due to test speeds or AEB intervention at a time where evasive steering may still be possible.

Many commenters stated that the expectation of no contact in the real world is not practical. The Alliance stated that while the research indicated that certain vehicles performed better under certain test conditions, the number of tests run, particularly at higher speeds, is insufficient to make any reliable determination as to the repeatability and reproducibility of testing and that the agency ran only one test per vehicle at each of the different speed ranges in each scenario. Many commenters also observed that no vehicle was found to have met all the proposed requirements.

Further, the Alliance described two aspects of brake performance that they suggested should be considered. First, they stated that peak deceleration capability of the vehicle is generally limited by the tire adhesion and is therefore not likely to be impacted by brake hardware changes, and performance today typically exceeds the mandated performance from FMVSS No. 135 or FMVSS No. 105. The second aspect of brake performance which the Alliance stated must be considered is the time factor to reach the target deceleration.

Honda, Nissan, and other commenters stated that the proposed test requirements do not consider the trade-off between collision avoidance through evasive steering and emergency braking, leading to increased concerns for false activations. Further, Honda stated that to meet the proposed higher speed no-contact requirements, current systems would be forced to provide braking intervention with significantly reduced recognition reliability and that current AEB systems would need to be completely redesigned.

Bosch stated that its testing shows that when the speed reaches approximately 75 km/h, there are reproducibility challenges with multi-sensor fusion of the object in time to initiate AEB and avoid the obstruction, and considerations should be made on how these requirements align with current functional safety requirements.

Volkswagen stated that they conducted an analysis using the Crash Investigation Sampling System (CISS) where data from rear-end crashes were collected from Event Data Recorder (EDR) data. The results were that there were no injuries above the Vehicle Abbreviated Injury Scale (VAIS) of 3+ in this small sample, noting that this was a non-statistically significant sample of 56 rear end crashes below a relative collision speed of 50 km/h.

MEMA stated that they agreed with the NHTSA alternate proposal for contact which, consistent with European regulations, allows low speed contact during testing. MEMA suggested a no-contact test requirement at speeds up to 25 mph (roughly 40 km/h), and a realistic speed reduction requirement above this speed (*i.e.,* collision mitigation). Hyundai stated that a target deceleration rather than no contact should be used as the appropriate criterion for assessing AEB performance.

HATCI stated that the requirements for damageability from 49 CFR part 581 address the need to reduce severity of any impact following activation of AEB, such that reductions in fatalities and injuries are achieved without stipulating no contact. Further, HATCI stated that the part 581 bumper standard speeds do not cause damage to the vehicle or Global Vehicle Target (GVT) and are highly unlikely to cause injuries to the vehicle occupants.

Mitsubishi stated the agency should allow for maximum contact speed instead of no contact, especially for higher test speeds, as the NPRM's proposed requirement would require OEMs to fully redesign their AEB systems, including new hardware. Further, Mitsubishi stated that the benefit for systems which allow a low speed, such as a 10 km/h, impact to the rear-end of another vehicle can be considered comparable to no contact in terms of fatal or severe injury likelihood. Mitsubishi also stated that they opposed a regulatory requirement whose purpose appears to be reduction of the test burden by seeking to avoid rebuilding the strikable target when impacted. Therefore, Mitsubishi stated that they suggest 1) allowing low speed contact, 2) eliminating the higher approaching-speed test, and 3) securing reasonable headway distance, particularly with higher speed of the decelerating lead-vehicle scenarios.

FCA raised issues with whether the no-contact requirement was appropriate for vehicles with greater mass. FCA provided a graph developed from their research that suggests that as test weight went up, the overall pass (contact) rate went down.[92] FCA stated that this means one of two things: heavier vehicles installed less capable AEB systems or otherwise if all AEB systems were comparable, then the test weight of vehicle hardware could be a dominant factor in the compliant ''no-contact'' outcomes.

Furthermore, FCA stated that the proposed requirements that the subject vehicle under test ''does not collide'' is subjective. The soft coverings over both devices will have dimensional variation as they exhibit wrinkles and folds or fluttering. FCA stated that they do not understand what ''not collide'' means in this context. FCA suggested NHTSA investigate this concept and make a new proposal as to what ''collide'' means as an objective, regulatory concept.

Agency Response

This final rule adopts the full collision avoidance (*i.e.,* no-contact) requirement proposed in the NPRM, which requires that the subject vehicle must not contact the lead vehicle in all AEB performance tests listed in the regulation. After considering all comments and for the reasons discussed below, the agency believes that the proposed no-contact requirement continues to be the most appropriate. NHTSA does not believe that further investigation is necessary to determine what collide means, in the context of this rule.

No Contact Provides Maximum Safety Benefits and Is Consistent With the Safety Act

As noted in the NPRM, one of the primary reasons for choosing the no-contact requirement in lead vehicle AEB tests is to maximize the safety benefits of the rule. Many commentors agreed

[92] *https://www.regulations.gov/comment/NHTSA-2023-0021-0999,* see page 9.

with the agency's decision to obtain maximum benefits to the public. Advocates stated that allowing contact during AEB testing will lessen the strength/benefit of the rule. Similarly, NTSB stated that the no-contact requirement is consistent with the need for safety and should be mandated to obtain the best possible safety outcome. Further, AAA and NSC stated that the no-contact requirement could eliminate millions of injuries and thousands of fatalities over a five-year period. Alliance acknowledged that the alternative approaches proposed by the organization could provide meaningful safety gains (not the best benefit). As for additional benefits of the requirement, we agree with Luminar that the no-contact requirement also provides economic benefit by reducing the total cost of vehicle ownership with insurance savings.

NHTSA agrees with the commenters who stated that obtaining safety benefits is crucial for this final rule. NHTSA agrees with IIHS that some current systems are already completely avoiding collisions under the proposed lead vehicle AEB testing more than five years before this rule will take effect. One vehicle discussed in the additional research section performed very well and passed all lead vehicle AEB requirements except for only the most stringent condition under the lead vehicle decelerating scenario—satisfying the requirements in two out of five tests. Thus, the outcome of that additional confirmatory testing is encouraging and demonstrates that these requirements are practicable. The testing results provided by IIHS in their comment provide NHTSA with additional evidence that the requirements are within reach for manufacturers because the technology exists and the final rule provides sufficient lead time.

The No-Contact Requirement Is Practicable

The commenters who opposed the no-contact requirement and asserted that it is not practicable rely heavily on the 2020 testing and that no single vehicle achieved compliance in any single run. This assertion rests on misunderstandings of the applicable law and a failure to consider the trajectory of the technology and its performance.

First, no single vehicle must meet every requirement for an FMVSS to be considered practicable under the Safety Act. The Sixth Circuit in *Chrysler Corp.* v. *Dep't of Transp.* provided detailed analysis of the technology-forcing authority possessed by NHTSA and the legislative history that reinforces the court's conclusion.[93] The Sixth Circuit stated:

''[the] explicit purpose of the Act, as amplified in its legislative history, is to enable the Federal government to impel automobile manufacturers to develop and apply new technology to the task of improving the safety design of automobiles as readily as possible.'' [94] The Senate Report also states that Congress rejected the Automobile Manufacturers Association's attempt to bind the rate of innovation imposed by safety standards to the pace of innovation of the manufacturers.[95] Similarly, the House Report states that NHTSA should consider all relevant factors when considering whether a safety standard is practicable, ''including technological ability to achieve the goal of a particular standard.'' [96] The Sixth Circuit rightly points out that there would be no need for NHTSA to consider technological ability to achieve a particular safety goal if NHTSA was limited to issuing standards that reflected the current state of technology.[97] The court ultimately ruled that NHTSA is empowered by the Safety Act to issue FMVSS that require improvements in existing technology or that might even require development of new technology.[98]

Second, NHTSA has evidence that AEB performance improved dramatically between 2020 and 2023 model years. Considering the marked improvement in AEB system performance demonstrated in NHTSA's additional testing, NHTSA finds that manufacturers are already coming close to meeting the requirements of this final rule.

The agency disagrees with commenters that the no-contact requirement is not practicable because no vehicle in the agency's 2020 research met all lead vehicle AEB tests as presented in the NPRM. We believe that the vehicles used in the 2020 research were designed with the intention to meet the demands from the 2016 voluntary commitment and the existing U.S. NCAP. As presented in the NPRM, these programs demand a much lower level of AEB performance than those of this final rule. For example, the highest test speeds of the 2016 voluntary commitment and the NCAP are both 40 km/h (25 mph) in a lead vehicle stopped test scenario. On the other hand, the highest subject vehicle test speed of this rule for the same scenario is 80 km/h (50 mph)—much higher than that of the programs. Even though the AEB systems were designed with substantially low target performance goals, three out of eleven vehicles in the 2020 research were able to meet the no-contact requirement at the speed up to 72.4 kph (45 mph) in the lead vehicle stopped test scenario.

NHTSA conducted additional AEB research with six model year 2023 vehicles (from six different manufacturers) using the performance requirements and test procedures of this final rule.[99] The results of this additional research demonstrated that one vehicle was able to meet the no-contact requirement at least once in all required lead vehicle AEB test conditions. Thus, the technologies needed to make the AEB systems which can meet the no-contact requirement and other performance requirements of this final rule are currently available. IIHS also observed similar results, which they assert indicate that some existing AEB systems are able to completely avoid collisions in the required lead vehicle AEB testing conditions.

Furthermore, in analyzing whether an FMVSS is objective, practicable and meets the need for motor vehicle safety, NHTSA must balance benefits and costs and consider safety as the preeminent factor in its considerations.[100] NHTSA believes that lowering the performance requirement to one that allows for contact would fail to treat safety as the preeminent factor for this final rule and otherwise be inconsistent with the goals of the Safety Act.

[93] 472 F.2d 659 (6th Cir. 1972).

[94] *Id.* at 671, citing S.Rep. 1301, 89th Cong., 2d Sess., 2 U.S.Code, Cong. and Admin.News, 2709 (1966).

[95] S.Rep. 1301, 89th Cong., 2d Sess., 2 U.S.Code, Cong. and Admin.News, 2709 (1966), which states ''In fact, specific efforts by the Automobile Manufacturers Association to tie the rate of innovation imposed by safety standards to the pace of innovation of the manufacturers were rejected by the House Committee on Interstate and Foreign Commerce, and the reported bill proposed that safety standards be ''practicable, meet the need for motor vehicle safety, and be stated in objective terms.''

[96] H.R. Rep. 1776, p. 16.

[97] 472 F.2d at 672.

[98] *Id.* at 673.

[99] NHTSA's 2023 Light Vehicle Automatic Emergency Braking Research Test Summary, available in the docket for this final rule (NHTSA–2023–0021).

[100] *See, e.g., Motor Vehicle Mfrs. Assn. of United States, Inc.* v. *State Farm Mut. Automobile Ins. Co.,* 463 U.S. 29, 55 (1983) (''The agency is correct to look at the costs as well as the benefits of Standard 208 . . . When the agency reexamines its findings as to the likely increase in seat belt usage, it must also reconsider its judgment of the reasonableness of the monetary and other costs associated with the standard. In reaching its judgment, NHTSA should bear in mind that Congress intended safety to be the preeminent factor under the Motor Vehicle Safety Act.'').

Increasing Unintended Consequences

In the comments, vehicle manufacturers and equipment suppliers expressed concern that the no-contact requirement may cause some unintended consequences, such as increasing false positive activations and taking away driver's authority at a high speed.

As for the false positives, the concern is based on a hypothetical situation that the no-contact requirement might cause a vehicle to prematurely activate the AEB system from a far distance where there is not a true risk of an imminent crash. The rationale is that the vehicle would be forced to initiate an early braking to achieve a full collision avoidance. These comments represent a combination of concerns—concerns with the no-contact requirement and concerns with the maximum speed in the testable range. This section addresses only the issue of no contact. Other related issues are addressed in the appropriate sections.

NHTSA does not expect that false activation would occur for well-designed systems. NHTSA recognizes that false activation could occur when an AEB system has low accuracy and reliability. As mentioned previously, we agree with Luminar and other commentors that no-contact performance is within the capability of existing technology. For example, Honda asserted that an AEB system will likely intervene improperly when the road in front of a subject vehicle is curved to the left and there is a vehicle parked on the right side of the road that causes no risk of collision. If the subject vehicle is equipped with sufficient technology to detect the shape of the road ahead, the AEB system would not improperly activate based on the mere fact that a parked vehicle appeared in the middle of AEB's field of view. There are manners in which an algorithm can assess the shape of the road. The system will also be continuously receiving more data as the vehicle gets closer.

Another technical option is having redundant systems as suggested in the Alliance's comment. Regardless of whatever technical solution manufacturers choose, NHTSA does not believe that it should lower performance to match that of poor performers. Rather, manufacturers with poorly performing vehicles should strive to resolve their systems' deficiencies so that they can perform as well as the market's better or best performing vehicles.

Additionally, while this rule imposes performance requirements for AEB systems, it does not specify how manufacturers must meet the requirements. The agency is providing maximum flexibility to manufacturers in designing AEB system for their vehicles. NHTSA recognizes that different manufacturers have different economic and practical realities that face their businesses. NHTSA principal concern is with the safety outcome and not the path that a manufacturer chooses to take to get to the required outcome. Given the various technical options, selecting technology for their AEB systems and setting the level of accuracy and reliability are at the manufacturers' discretion. At the same time, the manufacturers should be responsible for any safety-related defects in their vehicle products, in this case potential false positive activations. Therefore, we expect that vehicle and equipment manufacturers will mitigate and resolve any product defect issues including potential false activation in their AEB systems. NHTSA will continue to monitor complaints on AEB systems from the public, including those involving false activations, and will evaluate the risks they present.

NHTSA does not agree with the Alliance and other commenters that an AEB activation at a high speed may remove a safer crash avoidance option from drivers. The AEB system presumably only starts braking when the system detects an imminent crash, which is the first thing NHTSA expects a driver would do. While last-minute steering by the driver intended to avoid a crash is another possibility, NHTSA is not persuaded this is the safest option or that it is incompatible with AEB activation. A steering maneuver to avoid a crash might succeed under very limited circumstances. First, there must be another lane adjacent to the primary lane where a subject vehicle and a target vehicle are located. Second, a sufficient space must also be available in the adjacent lane. Finally, the driver must have the ability to safely maneuver a vehicle at such a high speed. Regardless, nothing in this rule specifies what an AEB system must do when a driver executes a steering maneuver to avoid a crash.

Global Harmonization Is Not Possible for No Contact Because it Unreasonably Lowers the Safety Benefits Received by the Public

NHTSA received comments that requested NHTSA to reject the no-contact requirement and adopt UNECE Regulation No. 152 requirements that permit low speed contact. Consistent with NHTSA's longstanding commitment to international harmonization [101] and section 24211 of BIL, NHTSA cooperates to the maximum extent practicable with respect to global harmonization of vehicle regulations as a means for improving motor vehicle safety.

NHTSA has been a leader in various international forums that impact vehicle safety for decades. The primary forum in which NHTSA engages in these activities is UNECE World Forum for Harmonization of Vehicle Regulations (WP.29). This international work is crucial to NHTSA's safety mission because it allows the agency to share its knowledge and expertise with foreign counterparts around the world, and for NHTSA to learn from its foreign counterparts. It also allows for NHTSA to advocate for standards that meet NHTSA's robust requirements and improve safety is measurable ways. Analysis of safety benefits provide NHTSA with a good understanding of the expected impact of its regulations. Such analysis is not necessarily required or conducted at WP.29.

NHTSA does not interpret section 24211 of BIL as requiring that NHTSA adopt harmonized regulations for the primary purpose of harmonization. To adopt this interpretation would be inconsistent with the text of section 24211 and the Safety Act. NHTSA interprets section 24211 as requiring NHTSA to promote safety in global forums. NHTSA believes that ''as a means for improving motor vehicle safety'' is intended to convey that the requirement to harmonize has the goal of improving motor vehicle safety. In situations where adopting an international or regional regulation would result in reducing motor vehicle safety, NHTSA does not believe the agency carries any obligation under the abovementioned section to adopt regulations that result in lower performance.

UNECE Regulation No. 152 was drafted by entities under an agreement to which NHTSA is not a party, and it was drafted years before NHTSA's NPRM. The testing NHTSA has conducted in support of this rule indicate that the industry has made substantial progress between 2020 and 2023 model years. NHTSA's adoption of more stringent requirements than existing UN Regulations indicates NHTSA's commitment to maximizing safety.

[101] *https://www.federalregister.gov/documents/1994/03/08/94-5181/revision-of-the-1958-united-nations-economic-commission-for-europe-agreement-regarding-the.*

Variability and Compliance Margins

FCA's comment indicates that it is concerned both about variability and about the compliance margins it thinks may be necessary for it to ensure compliance with this rule. First, FCA commented that the no-contact requirement would force early decisions and that the NPRM did not discuss why, in multiple runs, vehicles can pass some but not all tests without contacts. From NHTSA's perspective, the variability seen in NHTSA testing is expected because the systems tested were not designed to be compliant with the proposed requirements. As NHTSA has seen through its NCAP testing, manufacturers design systems to meet whatever thresholds are set, and when they do that, their vehicles are designed to pass those tests. This suggests to NHTSA that the variability in the NHTSA testing is due to the fact that no manufacturer has designed their systems to meet all of these requirements. While NHTSA understands that industry is concerned about the stringency of the no-contact requirement, variability does not seem to be at the heart of that issue.

FCA also raised concerns about the compliance margins it believes may be necessary for its products to comply with the no-contact requirement. Compliance margins are usually manufacturer dependent due to a variety of reasons that include the fact that each manufacturer establishes a different level of organizational risk acceptance and each manufacturers' products are usually unique to that manufacturer. As stated in the FRIA accompanying this rule, different manufacturers may have differing compliance margins with which their companies are most comfortable. Differing compliance margins and overall organizational risk management practices can impact the product and costs to make that product. Manufacturers are free to choose what compliance margins make sense for their organization and their products, and NHTSA does not dictate that. NHTSA establishes a minimum level of performance and manufacturers are required to ensure that their products meet that minimum level.

NHTSA's Testing Is Sufficient To Support This Rule

The testing conducted by the agency included the most common rear-end crash scenarios across several speeds and included a range of vehicle types and both camera and radar and camera fusion systems. In the case that the vehicle met the requirements (no contact) for a specific crash scenario and speed, testing continued at higher speeds. For the Lead Vehicle AEB testing, each vehicle was tested five to seven times for each scenario and speed combination. For the PAEB testing, each vehicle was typically tested five times for each combination of scenario, speed, and lighting condition.

In the absence of unlimited time and resources, it is not possible to test every vehicle across each combination of scenario, speed, and condition. Further, contact with a target object has the potential to compromise future test runs. Even relatively low speed impacts can result in a misalignment of forward-looking sensors, particularly those mounted behind lower trim and/or the grill. As a result, subsequent (*i.e.,* post impact) tests may not be representative of the vehicle condition at time of first sale.

The vehicles included in the testing conducted by the agency include a variety of body styles including heavier vehicles such as SUVs and pick-up trucks. The heavier vehicles included in testing NHTSA used to support the NPRM were Ford F–150 SuperCrew, Mercedes-Benz GLC 300, Hyundai Palisade, Audi Q5, and Range Rover Sport. The vehicles that NHTSA tested also included a mix of camera only and radar and camera fused systems utilized by model year 2020/19 vehicles.

Furthermore, NHTSA performed additional confirmatory testing that included 2023 model years. This testing showed that the models tested performed even better than those in 2020, which supports NHTSA's position that this rule is not only achievable but very close to being within reach for many manufacturers. NHTSA believes that the research from 2020 and 2023 is sufficient to support this final rule.

d. No-Contact Requirement for Pedestrians

Similar to the lead vehicle AEB performance test requirements, NHTSA proposed that PAEB-equipped vehicles must completely avoid a collision with a pedestrian test mannequin during specific test track scenarios. NHTSA requested comment on the same two alternatives to a no-contact requirement for pedestrian performance test requirements.

NHTSA notes that the positions taken by commenters for both lead vehicle AEB and PAEB are substantially similar, and therefore, much of what was said in the previous section also applies. This section primarily addresses issues specific to pedestrians.

Comments

IIHS stated that their evaluations of existing PAEB systems indicated that some current systems are completely avoiding collisions in the required PAEB testing conditions. IIHS stated that they began evaluating PAEB performance in new vehicles during the day in 2019 and at night in 2022. Furthermore, they stated that IIHS's PAEB ratings are based on a mixture of the data submitted by manufacturers for verification and the results from their internal testing. As of June 2023, IIHS stated that they rated 194 model year 2023 PAEB systems tested during the day. Of those, 33 (17 percent) fully avoided the pedestrian mannequin in every test condition. IIHS further stated that of the 114 model year 2023 PAEB systems tested at night, 12 (11 percent) fully avoided the pedestrian mannequin in every test condition.

MEMA commented that full avoidance is not reproduceable at higher velocities in low light conditions and in obstructed scenes. Due to external influences, MEMA contended that it is impossible to ensure that every test run is performed under the exact same conditions in this test, which is why it cannot be guaranteed that AEB will always achieve its maximum performance.

The Alliance stated that they suggest that the agency set the requirements of the regulation with the goal of minimizing the risk of serious injury in cases where vehicle to pedestrian contact occur, while providing for more certainty in making a determination to apply the brakes for crash avoidance and mitigation. Based on available research, the Alliance stated that establishing a no-contact requirement up to 30 km/h and a residual relative speed contact threshold not to exceed 25km/h would ensure the risks of sustaining a MAIS 3+ injury is well below 10%. Further, The Alliance stated that this exceeds the acceptable injury thresholds established in NCAP (for achieving a five-star rating) as well as the recommendations of Academic Expert Group for the 3rd Global Ministerial Conference on Road Safety. The Alliance stated that the suggested hybrid approach which would maintain the no-contact requirements at vehicles speeds up to 30 km/h but permit some level of contact if an acceptable speed reduction were achieved would reduce the potential for false positives under real world conditions.

Bosch stated that they wanted to address the ''no-contact'' requirement in performance testing and its implications for safety systems, particularly in the

context of pedestrian dummy detection and reaction. Further, Bosch stated that considering the challenge of detecting and reacting to the pedestrian dummy, there are still reservations concerning the no-contact requirement. Further, Bosch stated that they suggest that the criteria for collision mitigation systems be based on a certain amount of minimum speed reduction while considering injury-related assessments, such as the Head Injury Criteria (HIC) or similar measures (*e.g.,* acceleration exerted on the body during crash).

Agency Response

After considering the comments, the agency has concluded that the full collision avoidance requirement in PAEB tests, as proposed in the NPRM, is most appropriate for this final rule.

First, we agree with commenters that pedestrians could suffer severe injury at any speed in the testable range. Pedestrians are particularly vulnerable when coming in contact with a vehicle of any size. This is especially true when pedestrians are stuck by larger vehicles such as SUVs and pickup trucks. NHTSA believes that the increased vulnerability of pedestrians makes it even less desirable to permit any vehicle-to-pedestrian contact within the testable range.

Second, the impracticability argument raised by Alliance, MEMA and other manufacturers is not persuasive. That argument is primarily based on the agency's 2020 PAEB research presented in the NPRM, in which no vehicle met all required PAEB performance tests. The commenters assert that this reflects that the existing AEB related technologies are not ready for the level of PAEB performance required by this rule. However, we disagree with the commentors and believe that the results of the 2020 research are not indicative of shortcomings in the overall capability of the current PAEB technology. Rather, they are systems designed to meet a lower level of performance.

The agency conducted PAEB research with six model year 2023 vehicles (from six different manufacturers) using the proposed performance requirements and test procedures.[102] The results demonstrated that at least one vehicle was able to meet all performance requirements of this final rule. To the extent others do not, NHTSA has authority to issue technology-forcing standards when it is shown, as it is here, that meeting the standard is practicable.

[102] NHTSA's 2023 Light Vehicle Pedestrian Automatic Emergency Braking Research Test Summary, available in the docket for this final rule (NHTSA–2023–0021).

While the Alliance asserts that reducing impact speeds with pedestrians below 25 km/h could reduce the risk of serious injury, NHTSA believes that striking a person with a vehicle is not acceptable at any speed under any conditions. NHTSA included pedestrians in this rule because of their vulnerability and the trend of increasing pedestrian fatalities. Accordingly, we believe that retaining the no-contact requirement for the PAEB performance tests in the final rule is the most appropriate to ensure the maximum safety of the pedestrians.

e. Permissibility of Failure

As an alternative to the no-contact requirement with a single run that NHTSA proposed for lead vehicle AEB and PAEB, NHTSA sought comment on permitting the subject vehicle to use multiple test runs to achieve the performance test requirements. NHTSA provided background about how NHTSA's crash imminent braking and dynamic brake support testing within the New Car Assessment Program tests performance criteria, at the time of NPRM publication, specify that the speed reduction requirements for each test scenario must be met in at least 5 out of 7 tests runs. NHTSA stated this approach would provide a vehicle more opportunities to achieve the required performance and the agency more statistical power in characterizing the performance of the vehicle.

The agency also requested comment on the number of repeated tests for a given test condition and on potential procedures for repeated tests. The agency further requested comment on the merits of permitting a vehicle that fails to activate its AEB system in a test to be permitted additional repeat tests, including a repeat test process similar to that in the recent revisions to UNECE Regulation No. 152. Finally, the agency requested comment on whether there should be additional tests performed in the event no failure occurs on an initial test for each series.

The Advocates, Forensic Rock and AAA oppose allowing repeated test trials in all test situations. Forensic Rock stated test failures should not be allowed when performing testing under ideal conditions. AAA stated that repeated tests would lead to ambiguity around whether a vehicle that has previously passed the test should be retested.

The ASC, ZF, Humanetics, MEMA, Bosch, Mitsubishi, the Alliance, Porsche, Hyundai, Aptiv, Rivian, and Volkswagen all support allowing repeated test trials. ASC, ZF, Humanetics, MEMA, Bosch, and the Alliance specifically acknowledge that testing with a 5 out of 7 passing threshold for the speed reduction tests would be appropriate. Rivian recommends running between 3 and 5 tests and averaging the speed reduction achieved with a passing grade being given to vehicles that average greater than a 50 percent speed reduction. The Alliance and Porsche also recommend that a vehicle could pass after three consecutive successful tests. ASC and ZF recommend that repeated trial testing be used at speeds of 25 mph and higher. ZF recommends that the speed reduction targets should be data driven based on speeds where there is a severely limited risk of injury to pedestrians or vehicle occupants. ZF, Porsche, Aptiv, Volkswagen and ASC also suggest the test requirements be aligned with UNECE Regulation No. 152 speed reduction requirements for daytime scenarios.

NHTSA is not including multiple test trials in this final rule. NHTSA agrees with commenters that allowing for repeated test trials, which would essentially permit a certain threshold of failures, under ideal test conditions is not acceptable. NHTSA believes that a single test run, and the expectation that a manufacturer pass all test runs if NHTSA chooses to run the same test several times, provides the performance consistency that consumers expect and safety demands. This is particularly true given that NHTSA will be conducting testing in idealized, controlled conditions when compared to real-world situations. For many years, NCAP testing and other testing around the world has permitted repeated test trials, and NHTSA believes that is appropriate for a technology that is new or being developed. However, for more mature systems with a long record of real-world use, NHTSA believes that a single test run is necessary to provide the agency the confidence that the performance it is regulating will perform as consistently as possible.

NHTSA believes it is even more important that PAEB perform in a single run with no contact due to the vulnerability of pedestrians in a vehicle-to-pedestrian crash. First, the speed ranges in which PAEB is expected to not contact a pedestrian mannequin during testing are lower than they are for lead vehicle AEB. Second, as with the no-contact provision, allowing for multiple runs is even more unacceptable for vehicle-to-pedestrian crashes because pedestrians are more vulnerable when being struck by a vehicle.

F. False Activation Requirement

NHTSA proposed to include two scenarios in which braking is not warranted. The agency proposed that AEB systems need to be able to differentiate between a real threat and a non-threat to avoid false activations. The two proposed false activation scenarios were the steel trench plate and the vehicle pass-through test scenarios.

1. Need for Requirement

NHTSA remains concerned that false activation events may introduce hard braking situations when such actions are not warranted, potentially causing rear-end crashes. The false activation tests establish only a baseline for system functionality. They are by no means comprehensive, nor sufficient to eliminate susceptibility to false activations. Rather, the tests are a means to establish minimum performance. NHTSA expects that vehicle manufacturers will design AEB systems to thoroughly address the potential for false activations. Vehicles that have excessive false positive activations may pose an unreasonable risk to safety and may be considered to have a safety-related defect. Previous implementations of other technologies have shown that manufacturers have a strong incentive to mitigate false positives and are successful even in the absence of specific requirements.

The two proposed false activation scenarios are the steel trench plate and the vehicle pass-through test scenarios. Both of these tests include acceleration pedal release and testing both with and without manual braking, similar to testing with a stopped lead vehicle. NHTSA proposed that, during each test trial, the subject vehicle accelerator pedal will be released either when a forward collision warning is given or at a headway that corresponds to a time-to-collision of 2.1 seconds, whichever occurs earlier. For tests where manual braking occurs, the brake is applied at a headway that corresponds to a time-to-collision of 1.1 seconds.

In the steel trench plate false activation scenario, a subject vehicle traveling at 80 km/h (50 mph) encounters a secured 2.4 m (7.9 ft) wide by 3.7 m (12.1 ft) long steel by 25 mm (1 in) thick ASTM A36 steel plate placed flat in the subject vehicle's lane of travel, and centered in the travel path, with its short side toward the vehicle (long side transverse to the path of the vehicle).

The pass-through test, as the name suggests, simulates the subject vehicle encountering two vehicles outside of the subject vehicle's path that do not present a threat to the subject vehicle. The test is similar to the UNECE Regulation No. 131 and UNECE Regulation No. 152 false reaction tests.[103] In the pass-through scenario, two vehicle test devices (VTDs) are positioned in the adjacent lanes to the left and right of the subject vehicle's travel path, while the lane in which the subject vehicle is traveling is free of obstacles.

The two stopped VTDs are positioned parallel to each other and 4.5 m (14.8 ft) apart in the two adjacent lanes to that of the subject vehicle (one to the left and one to the right with a 4.5 m (14.8 ft) gap between them). The 4.5 m (14.8 ft) gap represents a typical travel lane of about 3.6 m (11.8 ft) plus a reasonable distance at which a vehicle would be stationary within the adjacent travel lanes.

Comments

ASC, MEMA, Hyundai, Volkswagen, Mitsubishi, and the Alliance for Automotive Innovation submitted comments opposing the proposed false activation tests. ASC stated that EuroNCAP does not include a false activation test because the vehicle could be programmed to pass any specific false activation test. ASC further stated that the current sensors used in vehicles do not have the same susceptibility to false activations that the proposed tests were designed to identify. Volkswagen and Hyundai questioned whether the test scenarios were comparable to real world scenarios. MEMA and the Alliance stated that testing for two specific scenarios does not entirely represent what is required to design AEB systems that accurately discriminate between actual crash-imminent situations and false triggers. As a consequence, the commenters asserted that meeting the proposed performance requirements only increases testing burdens while not providing a good indicator of the likelihood of a system producing false activations in real world driving conditions.

Advocates, Humanetics, and Consumer Reports support the proposed false activation requirements, stating that to maximize safety and consumer acceptance, false activations must be limited as much as possible through test procedures included in the final rule. In addition, these performance-based tests are a more robust solution than a document-based approach. Adasky also supported including false positive testing.

Luminar Technologies stated that it is neutral on the matter of requiring the false positive testing as proposed or demonstration of false positive measures by the manufacturer in another way. Luminar believes that false positive testing is absolutely necessary for safety and to create public trust, but understands that in some situations, especially for future autonomous vehicles, that the proposed false positive scenario may not necessarily occur in the real world.

Porsche recommends NHTSA consider aligning false activation test requirements with those that are found on the UNECE Regulation No. 152.

Agency Response

The agency has retained the two false activation requirements including the steel trench plate and the vehicle pass-through scenarios. Like many NHTSA tests, the false activation tests do not cover all the situations in the real world where false activations can occur. However, NHTSA believes that these tests add value to the rule. The steel trench place test provides protection against a known engineering challenge for some sensing technologies. Road construction sites often include steel trench plates for which vehicles will encounter in the real world. Likewise, a vehicle driven particularly in urban areas often drives between parked cars on both sides of the road.

Manufacturers must be responsible for false activations regardless of FMVSS test requirements and must engage in the precision engineering to prevent false activation and unintended consequences. The industry responsibility does not mean that NHTSA should not include aspects of performance that products must continue to meet. NHTSA believes that issuing an FMVSS with false activation prevent testing underscores the industry responsibility and works to ensure better performing systems.

The comments from MEMA and Alliance suggests a potential need for more robust false activation testing. However, it is impossible for NHTSA to test all circumstances in which false activations may occur. That is not a logical basis for having no false activation tests. The commenters did not suggest additional tests for NHTSA to consider in this final rule.

NHTSA agrees with Advocates, Humanetics, and Consumer Reports that maximizing safety and consumer acceptance are essential elements to

[103] UNECE Regulation No. 131 (Feb. 27, 2020), available at *https://unece.org/fileadmin/DAM/trans/main/wp29/wp29regs/2015/R131r1e.pdf;* UNECE Regulation No. 152, E/ECE/TRANS/505/Rev.3/Add.151/Amend.1 (Nov. 4, 2020), available at *https://unece.org/fileadmin/DAM/trans/main/wp29/wp29regs/2020/R152am1e.pdf.*

help ensure the public receives the benefits of this technology. NHTSA agrees with Mitsubishi that ultimately protecting against the activation of AEB in situations where there is no imminent crash is the responsibility of the manufacturer. However, it is also appropriate for the FMVSS to set a minimum standard below which no vehicles should perform. While current systems may be less prone to false activations in the scenarios proposed, the scenarios represent known vulnerabilities in previous technologies. The tests ensure that performance of new technologies continue to provide the resistance to these false activation situations.

Considering Porsche's suggestion that NHTSA use the same false activation tests as the UNECE, NHTSA agrees that the curved road and turning scenarios that are part of UNECE Regulation No. 152 are relevant real-world conditions. Not all situations, however, can be tested through regulation. NHTSA is finalizing the two false activation tests it proposed because of the expected positive impacts they will have on system performance by preventing reemergence of prior performance issues and preventing other types of false activations.

2. Peak Additional Deceleration

NHTSA proposed that the AEB system must not engage the brakes to create a peak deceleration of more than 0.25g additional deceleration than any manual brake application generates (if used) in the steel trench plate false activation scenario. Similarly, NHTSA proposed that the AEB must not engage the brakes to create a peak deceleration of more than 0.25g beyond any manual braking in the pass-through test.

Comments

Consumer Reports suggested the threshold for maximum deceleration should be zero, especially under manual brake application. Consumer Reports opined that a 0.25g braking event is noticeable by passengers and could confuse or distract the driver. Consumer Reports asked that NHTSA remove any tolerance for false braking in these scenarios, or at the very least lower the threshold.

Agency Response

NHTSA is finalizing the braking criteria limit of 0.25g beyond manual braking as proposed. The agency balanced two factors in determining that a 0.25g criterion is more appropriate than using a 0.0g criterion. First, the ability to measure negative acceleration that results from the automatic application of the service brakes is difficult at low levels. As the total magnitude of deceleration increases, it is easier to establish that the service brakes are contributing as opposed to wind, tire friction, or engine drag. Second, it is unlikely that small levels of additional deceleration (less than 0.25g) could present a safety risk that could potentially lead to a crash.

3. Process Standard Documentation as Alternative to False Activation Requirements

As an alternative to the false activation requirements that were proposed, NHTSA requested comment on requiring manufacturers to maintain documentation demonstrating that robust process standards were followed specific to the consideration and suppression of false application of AEB in the real world. ISO 26262, ''Road vehicles—Functional safety,'' ISO 21448, ''Safety of the Intended Functionality (SOTIF),'' and related standards, are examples of this approach. The agency requested public comment on all aspects of requiring manufacturers to maintain documentation that they have followed industry process standards in the consideration of the real-world false activation performance of the AEB system.

Comments

Advocates, Mitsubishi, the Alliance for Automotive Innovation, Honda, and FCA opposed the agency's alternative to require that manufacturers maintain technical documentation that they have followed industry process standards. Advocates and Consumer Reports stated that documentation should not be used as a replacement for testing, but as a supplement to testing. MEMA, ZF and Volkswagen supported the technical documentation option presented in the NPRM.

Mitsubishi explained as part of its opposition to technical documentation that it is impossible to predict all false-positive scenarios and be able to generate technical documentation for it. The Alliance stated such a requirement will increase the administrative burden on manufacturers with no added safety benefit. FCA and Mitsubishi stated that the suggested processes standard, like ISO 26262 or SOTIF, should not be an element of any FMVSS. FCA also stated that any FMVSS should be purely about a vehicle presented to a test site and with performance assessed according to objective criteria. FCA further stated that it is not necessary for the agency to understand how a product was developed to meet a minimum performance requirement, just that it does. Finally, FCA noted that NHTSA has other information gathering powers over industry (*e.g.,* the current ADAS Standing General Order) and development practices or engineering methods should fall under that authority, not as part of an FMVSS.

In its support for a technical documentation requirement, ZF stated that, although they do not recommend a false activation test, they agree that efforts should be made in system design to mitigate against that risk. ZF supported some documentation to demonstrate efforts had been made in system design to prevent false activation. Volkswagen stated the most effective way to combat false positives is during the development process. Volkswagen and ZF both considered the suggested documentation requirements on measures taken against false positives to be a suitable approach.

Agency Response

After considering comments, NHTSA has opted not to include a requirement in the FMVSS that manufacturers maintain documentation of the application of process standards during AEB system development. Instead, the agency chooses to keep the false activation tests proposed and incorporate them into this final rule. NHTSA believes that performance testing of final products remains an important compliance tool for the agency.

Even though the agency is not finalizing the documentation proposal, NHTSA disagrees with commenters who asserted that this sort of documentation is not of use to the agency. The agency believes that the application of process standards in good faith is likely to increase the chances that manufacturers have created products that minimize unreasonable safety risks. NHTSA agrees that the agency has other pathways through which it could seek this sort of information, including during an inquiry into the reasonableness of a manufacturer's certification and through a defect investigation. Therefore, it is not necessary to include such a requirement in the FMVSS.

4. Data Storage Requirement as Alternative to False Activation Requirements

As another alternative to the two proposed false activation tests, NHTSA requested comment on requiring targeted data recording and storage of significant AEB activations. As an example, NHTSA considered requiring that an AEB event that results in a speed

reduction of greater than 20 km/h (12 mph) activate the recording and storage of key information.

Comments

ASC, IIHS, MEMA, APCI, NTSB, and Forensic Rock supported data storage requirements. Advocates and Consumer Reports stated data storage requirements should not be used as a replacement for testing, but as a supplement to testing. ZF recommended that AEB system data be retained in some capacity by EDR systems. They stated that classification of the target that triggered the AEB activation may be useful for accident or false activation reconstruction. AAA and Rivian recommended the agency weigh how the data recording requirement would be implemented in the context of consumer privacy concerns. ASC stated its support of Event Data Recording (EDR) to assist in crash reconstruction and identification of false activation trigger factors. NTSB stated that without the data, it will be extremely challenging to determine whether and to what extent these systems were engaged during a crash. Forensic Rock stated that ensuring investigators have access to post-collision data that can objectively evaluate the performance of the AEB system in both lead vehicle and pedestrian collision scenarios is paramount and should be included in the FMVSS.

Honda, Bosch, Hyundai, Mitsubishi, the Alliance for Automotive Innovation and Volkswagen opposed requirements that would include AEB data storage. Honda stated that it was unclear as to the problem such a requirement would be meant to address. Bosch stated data recorders have limitations and are not able to determine whether a safety system's decision was reasonable, considering the provided sensor data. Hyundai stated it would entail significant burdens and unwarranted delays to this rulemaking and would provide no direct safety benefit. Mitsubishi stated a lack of objective and clear definitions of false activation indefinitely increases the data elements to record, which would require hardware reengineering. In addition, Mitsubishi stated that data is more likely to include privacy-sensitive information. The Alliance stated the agency has not provided any analysis on the technical feasibility of the proposal under consideration, nor has sufficient justification been made as to the practical utility of any data obtained as part of an information collection effort or the overall safety benefit to consumers. Volkswagen stated that to determine whether an activation was justified, camera data would be required in most cases and that storing camera data is not technically feasible for most current vehicle platforms due to processing and storage limitations of the existing architectures.

Agency Response

After considering comments, NHTSA is not including data storage as part of this FMVSS, and intends to keep the false activation tests that it proposed. NHTSA believes that the false activation tests will provide the minimum level of assurance that AEB systems will not provide unwarranted engagement. In the future, NHTSA can consider amending the EDR requirements established in 49 CFR part 563 and more broadly consider updates to vehicle data collection, event triggers for crash reconstruction, and potential gaps in performance of AEB and other safety systems. By looking at vehicle data holistically and considering the updates necessary to modernize 49 CFR part 563 and capture the information necessary for various driver assistance systems, the agency can further consider the data needs and associated burden to update the regulation to reflect the vehicle safety needs of today, current vehicle systems, and current manufacturer practices, while balancing privacy concerns.[104] Finally, regarding data manufacturers are already collecting, NHTSA has broad authority to request information from manufacturers during the course of investigations. Therefore, even absent a data recording requirement in an FMVSS or regulation, NHTSA expects that it can require manufacturers to provide the information that they are currently collecting on AEB systems.

G. Malfunction Detection Requirement

In the NPRM, NHTSA proposed that AEB systems must continuously detect system malfunctions. If an AEB system detects a malfunction that prevents it from performing its required safety function, the vehicle would illuminate a telltale that identifies (or indicates) the malfunction condition. The telltale would be required to remain active as long as the malfunction exists while the vehicle's starting system is on. NHTSA would consider a malfunction to include any condition in which the AEB system no longer functions as required by this rule. NHTSA proposed that the driver must be informed of the malfunction condition in all instances of component or system failures, sensor obstructions, or other situations that would prevent a vehicle from meeting the proposed AEB performance requirements. While NHTSA did not propose a specific telltale, NHTSA anticipates that the characteristics of the alert will provide sufficient information to the vehicle operator to identify it as an AEB malfunction.

1. Need for Requirement

The rationale behind the requirement that AEB systems continuously detect system malfunctions is that drivers would need to know when AEB is not functioning because AEB is an important safety system. NHTSA stated in the NPRM that it was considering minimum requirements for the malfunction indication to standardize the means by which the malfunction is communicated to the vehicle operator. Malfunctions of an AEB system are somewhat different than other malfunctions NHTSA has considered in the past. While some malfunctions may be similar to other malfunctions NHTSA has considered in FMVSSs because they require repair (loose wires, broken sensors, etc.), others are likely to resolve without any intervention, such as low visibility due to environmental conditions or blockages due to build-up of snow, ice, or loose debris.

Comments

Advocates, NAMIC, IIHS, MEMA and NTSB supported the proposed requirements for malfunction. NAMIC commented that it is important to include in a final rule a requirement that manufacturers notify the driver when AEB or other advanced driver assistance systems are malfunctioning or not performing as designed, and to include detailed directions for resolving the issue such as cleaning the sensor or going to a service center.

The Alliance stated that wording of the proposed malfunction requirements would likely result in excessive notifications to consumers and notifications that do not accurately communicate the status of the system. and may be misleading as to the actions required on the part of the driver to remedy the situation. The Alliance and Aptiv stated that it is not reasonable or practicable to require a manufacturer to detect changes in the roadway environment (*e.g.,* road surface condition) or the extent to which these changes may affect the performance of a vehicle in meeting the requirements of the rule. The Alliance, Consumer Reports, and ITS America commented

[104] With regard to consumer privacy, those concerns should be alleviated, at least partially, by the existence and application of the Driver Privacy Act of 2015, part of the Fixing America's Surface Transportation Act of 2015. The Driver Privacy Act assigned ownership of EDR data, as defined in 49 CFR 563.5, as the property of the owner or lessee of a vehicle. Importantly, it limits the access of EDR data to specific parties for specific purposes.

that malfunction failure indication should be limited to specific failures related to the hardware or software components that comprise an AEB system, not diminished performance due to environmental conditions such as heavy fog or snow.

The Alliance, NADA, and AAA recommended that NHTSA create separate definitions for ''malfunction warning'' and ''system availability warning'' to characterize these two conditions more accurately. Aptiv, Volkswagen, and Porsche suggested a warning based on UNECE Regulation No. 152 for non-electrical failures (for example, obstructions due to weather). Bosch suggested further specification in the warning of ''an appreciable time interval between each AEB system self-check.''

NTEA recommended that a compromised system function should not only warn the driver, but consider the possible prohibition of AEB activation. NTEA also provided cases where they feel sensors need self-monitoring abilities and temporary deactivation, such as a when going through a car wash or when overhead cargo is present that obstructs a portion of the forward camera's field of view.

Agency Response

The agency agrees with commenters who state that it is necessary that AEB systems monitor system health and notify the driver when a malfunction is present. Where the agency diverges from commenters is with regard to the need to require manufacturers to provide detailed information regarding the nature of the malfunction. The primary information necessary for a driver to determine if it is safe to operate the vehicle is simply whether the AEB system is working relative to the performance requirements of this new final rule.

The agency agrees with the commenters who stated that external conditions that limit system performance (such as minute changes in the road surface construction, the presence of sand or gravel on the road surface, etc.) are not malfunctions of the system, and in some cases, it is not possible to determine the AEB system's ability to perform. These conditions are often not readily measurable by vehicle sensors and are often temporary in nature.

NHTSA is clarifying that it did not intend to mandate that AEB perform in all environmental conditions. Rather, NHTSA requires that AEB systems function as required within the set of conditions provided in S6 of the regulatory text. The same is true for malfunction detection. NHTSA understands that there are differences between the driving environment hindering ideal AEB performance and true malfunctions of the system that likely require intervention to resolve. To give an example, snow might cause degraded performance for a variety of reasons, but a malfunction notification would not be necessary unless that snow results in deactivation of the AEB system, such as a situation when the snow obstructs the AEB sensors, causing the system to not meet the performance requirements. Alerting the driver to this type of malfunction is vital to the safe operation of the vehicle. Any notification of degraded system performance arising from any source (temporary or permanent) should end when the conditions that lead to the degradation end.

Therefore, this final rule clarifies that if the system detects a malfunction, or if the system adjusts its performance such that it will not meet the performance requirements, the system must provide the vehicle operator with a telltale notification. This requirement makes clear that if the system reduces its performance capabilities (regardless of if the reason is because of environmental conditions or for other reasons), the driver must be informed. Also, if the system is broken or a sensor is obstructed, the driver must be informed. However, if there are environmental conditions that decrease the system's ability to function (for instance decreased stopping distance) but the system has made no internal adjustments, a telltale is not required.

As for the issue of separate telltales to inform the driver of permanent and temporary malfunctions, the requirement proposed and adopted here was intended to give manufacturers flexibility in the style and nature of the driver malfunction notification. The requirements allow for different notification types for different types of degraded performance (*e.g.,* internal malfunctions or external conditions) that degrade performance, should the manufacturer choose to do so. The manufacturer may also, at the manufacturer's discretion, choose to use the same telltale or other notification for the different types of degraded performance. NHTSA has observed that some manufacturers currently do this and nothing in the NPRM was intended to prohibit this. This is consistent with the malfunction warning requirements in UNECE Regulation No. 152.

The agency appreciates Bosch suggesting a more specific definition, but NHTSA is not adopting the proposed definition for malfunction detection provided at this time because it is not workable for an FMVSS. For example, ''appreciable time interval'' is not an objective measure of timing, nor does it give manufacturers notice as to what NHTSA expects of them. Furthermore, NHTSA does not have a basis for why it would treat electrical failure conditions differently than any other type of system malfunction, as suggested by Bosch.

Regarding NTEA's suggestion that NHTSA prohibit AEB activation in the instances where a malfunction may be present, NHTSA does not believe that mandating the prohibition of AEB activation is necessary since there is no evidence that a manufacturer would permit its systems to function in a state so degraded as to present an unreasonable risk to safety.

2. Malfunction Telltale

NHTSA did not propose the specifics of the telltale but anticipated that the characteristics of the alert would provide sufficient information to the vehicle operator to identify it as an AEB malfunction, and would also be documented in the vehicle owner's manual. NHTSA requested comment on the potential advantages of specifying test procedures that would describe how the agency would test a malfunction telltale and on the related level of detail that this regulation should require. The agency also requested comment on the need and potential safety benefits of requiring a standardized appearance for the malfunction telltale and what standardized characteristics would achieve the best safety outcomes. The agency further requested comment on the use of an amber FCW warning symbol as the malfunction notification.

Comments

The Alliance and Nissan commented that specifics of a telltale for malfunction (and related system status) should be defined by the manufacturer. Nissan observed that UNECE Regulation No. 152 does not define the specific form of the malfunction telltale.

ASC suggested that the agency require an AEB malfunction telltale to be located on the vehicle's instrument panel. ASC stated that on start-up, the AEB system could run diagnostics and trigger the malfunction telltale if a failure or obstruction is detected.

However, several other commenters suggested standardization of a common malfunction telltale. ZF and MEMA suggest a telltale modeled after the ESC telltale, in an effort to better alert the driver to an AEB malfunction.

Toyota stated that an amber telltale may be appropriate, as it aligns with

similar malfunction requirements, such as those in FMVSS No. 135.

IIHS commented that NHTSA should require manufacturers to notify the driver when AEB or other ADAS are malfunctioning or not performing as designed. They noted that, ideally, the notification should provide directions for resolving the issue, such as cleaning the sensor or going to a service center, noting that drivers should not be expected to troubleshoot misbehavior or malfunctions from their ADAS, especially when the malfunction introduces new risks. They provided two examples of a vehicle with a misaligned radar following a crash and a skewed camera following a windshield replacement, which did not provide an indication of malfunction or reduction of performance.

AVIA commented that for AVs, NHTSA should consider adding language that allows a malfunction detection notification to be directly communicated to the ADS itself or communicated to a remote assistant or to service personnel in the case of an AV without manually operated driving controls. They added that for an ADS-equipped vehicle with manually operated driving controls, the notification can be directly communicated to the ADS when it is engaged as well as through a telltale notification to the human operator. Zoox commented that the malfunction telltale requirement should specify that it be visible from the driver seating position and that, for vehicles without a driver seating position, the mechanism is specified by the manufacturer and provided upon request, and suggested that testing not be conducted while an equivalent notification to the telltale is active for vehicles without a driver seating position.

Agency Response

NHTSA agrees that the specifics of a telltale for malfunction should be defined in detail by the manufacturer. The agency has concerns, however, about drivers confusing a malfunction indicator that is co-located with the FCW symbol. As such, Toyota's suggestion to align the malfunction telltale with the FCW symbol may be problematic. The agency is concerned about confusing drivers, because using the same telltale could be interpreted as asking the driver to brake or as a malfunction.

NHTSA understands the positions of commenters who requested a standardized malfunction telltale. Nothing prohibits the industry from working together, such as through a standards organization, to implement a common telltale. However, NHTSA does not believe standardization is necessary at this time. Commenters did not provide sufficient evidence to demonstrate a need for a standardized malfunction indicator. Thus, NHTSA is not adding additional constraints on the telltale, in this final rule. If warranted, NHTSA would consider standardization if in the future it is determined that drivers do not adequately comprehend when an AEB malfunction has occurred.

NHTSA does not agree with ASC's suggestion of a standardized location for a telltale. FMVSS No. 101 does not provide specification for the location of any telltale except that it be visible to the driver when a driver is restrained by a seat belt. There is no evidence of a safety need for any more specific location requirement for an AEB system malfunction telltale.

As discussed in other sections, NHTSA agrees with IIHS that the driver should be notified when AEB is malfunctioning, which is the entire goal of a malfunction telltale requirement. NHTSA does not believe that it is necessary to notify drivers of the directions for resolving the issue, but that such information could be provided to drivers in the owner's manual. A driver who is driving on the street doesn't need to be told while the vehicle is moving that she needs to clean the sensor. Rather, this is diagnostic information that could be communicated through other means, like through the use of diagnostic tools accessing information in the OBD–II port.

As for the comments related to AVs, NHTSA believes it is most appropriate to address specific concerns related to AVs through other mechanisms, rather than shaping this particular FMVSS around the needs of a very specific set of vehicles that may still have to apply for an exemption from other FMVSS. NHTSA is considering crash avoidance test procedures to facilitate the safe introduction and certification of new vehicle designs equipped with automated driving systems in a separate rulemaking.[105] NHTSA is also looking across all FMVSS to address the applicability and appropriateness of safety messaging (telltales, indicators, and warnings) in new vehicle designs without conventional driver controls.[106] Additionally, NHTSA notes that manufacturers are free to design their vehicles to have the malfunction detection notification be communicated directly to the ADS, a remote assistant or service personnel, as a redundant means of communication. Such redundancy is permissible in situations that a manufacturer believes it is necessary.

3. Sensor obstructions and testing

NHTSA proposed that the driver must be warned in all instances of malfunctions, including malfunctions caused solely by sensor obstructions. The NPRM also proposed that during track testing of the AEB system all sensors used by the system and any part of the vehicle immediately ahead of the sensors, such as plastic trim, the windshield, etc., would be free of debris or obstructions. NHTSA stated that it was considering requirements pertaining to specific failures and including an accompanying test procedure.

Comments

The Alliance stated that it is important that NHTSA define a finite set of scenarios that could be reasonably defined as a malfunction, should the agency decide to regulate in this area, to ensure that relevant scenarios are being addressed, and that other factors that may influence AEB performance are evaluated independently. Mobileye recommended performing full blockage camera/radar testing as in the Euro-NCAP Assisted Driving protocol. ZF also suggested testing by obstructing sensors. Rivian recommended that NHTSA adopt detailed procedures that can be performed on the test track and are representative of relatively high frequency occurrence in actual use cases. ZF commented that malfunction indicator light testing could be done by deliberately blocking for radar to simulate snow accumulation, or a piece of tape for cameras to simulate a lens blockage.

Agency Response

After considering the comments, NHTSA is not making any further specifications of failures that would be tested. As is customary with NHTSA's standards, the laboratory compliance test procedures will specify how NHTSA intends to run its compliance test regarding illumination of a malfunction telltale.

H. Procedure for Testing Lead Vehicle AEB

This section describes the lead vehicle AEB performance tests adopted by this final rule. After considering the comments to the NPRM, NHTSA has adopted the proposed procedures with a few changes. Some minor parameters

[105] *https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2127-AM00.*

[106] *https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2127-AM07.*

and definitions were modified and various definitions were added, to clarify details of the test procedures. Additionally, to increase the practicability of running the tests, a third manual brake application controller option, a force only feedback controller, has been added. The force feedback controller is substantially similar to the hybrid controller with the commanded brake pedal position omitted, leaving only the commanded brake pedal force application.

This section responds to the comments and explains NHTSA's reasons for adopting the provisions set forth in this final rule. For the convenience of readers, a list of the test specifications can be found in the appendix A to this final rule preamble.

The lead vehicle AEB performance tests require a vehicle to automatically brake, or supplement insufficient manual braking, when tested during daylight under three specific test scenarios. The scenarios involve a stopped lead vehicle, a slower-moving lead vehicle, and a decelerating lead vehicle. The performance criterion for all AEB tests involving a lead vehicle is full collision avoidance, meaning the subject vehicle must not contact the lead vehicle.

The lead vehicle AEB tests include parameters necessary to fully define the initial test conditions in each scenario. Key test parameters for the lead vehicle AEB tests include the travel speed of both the subject vehicle and lead vehicle, the initial headway between the subject vehicle and the lead vehicle, the deceleration of the lead vehicle, and any manual brake application made to the subject vehicle. For each test run conducted under each of the scenarios, NHTSA will select the subject vehicle speed (V_{SV}), lead vehicle speed (V_{LV}), headway, and lead vehicle deceleration from the ranges specified in the standard.[107]

There will be testing under two conditions. In one condition, NHTSA will test without any manual brake application. This would simulate a scenario where a driver does not intervene at all in response to the FCW or impending collision. In the other condition, NHTSA will test with manual brake application that will not be sufficient to avoid the crash. Not only will the second condition ensure that the AEB will supplement the manual braking when needed, it also provides a way to ensure that an application of insufficient manual braking will not suppress automatic braking in circumstances where automatic braking is initiated before the manual brake application is used.

1. Scenarios

Many commenters suggested including additional scenarios in lead vehicle AEB testing.[108] Many commenters urged NHTSA to include lead vehicle AEB testing in the dark to increase the benefits of the rule. The Lidar Coalition commented that it supports testing AEB in the darkest realistic conditions possible. It stated that a test procedure in dark conditions would evaluate AEB and PAEB technologies in the real-world scenarios where these systems are most needed because of diminished visibility. Forensic Rock state that they found differences in the performance of a specific vehicle's AEB system during the day as compared to testing under the same conditions at night and that to comprehensively evaluate the performance of AEB systems, daytime and nighttime tests should be conducted under the same closing speeds. Advocates suggested that NHTSA evaluate and present data demonstrating that the exclusion of testing lead vehicle (vehicle-to-vehicle) AEB under dark conditions is not limiting the performance level demanded by the proposed rule nor needlessly jeopardizing safety.

In response, NHTSA appreciates the interest in including additional scenarios to potentially assess AEB systems under a wider range of potential real-world situations. NHTSA does not, however, include further tests in this final rule. The decision to include a particular test scenario depends on various factors, including the safety benefit resulting from a requirement, the practicability of meeting the requirement, the practicality and safety of conducting a test, and, in accordance with E.O. 12866, the likelihood that market forces will incentivize manufacturers to provide the needed performance absent the requirement. NHTSA at present does not have sufficient supporting data to assess the need for, practicability of, or practicalities involved with adding darkness test scenarios to the lead vehicle AEB tests. This is in contrast to the PAEB test, which includes darkness test scenarios.

There is not enough data supporting a finding for a safety need for a darkness test. The test scenarios of this rule broadly represent real world situations by sampling the most common types of light vehicle rear-end crashes. In NHTSA's latest testing described earlier in this document, the agency observed that vehicle performance during the dark ambient tests were largely consistent with those produced during the daylight tests (in the absence of a regulation). The dark- compared to day-contact results observed for a given test speed were identical or nearly identical for several of the vehicles tested. Where impacts occurred, the impact speeds were very similar. Additionally, as detailed in the safety problem section of this preamble, 51 percent of rear end crash fatalities occur during daylight, and injury and property-damage-only rear-end crashes were reported to have happened overwhelmingly during daylight, at 76 percent for injury rear-end crashes and 80 percent for property-damage-only rear-end crashes.

Some data indicate that there may not be a technical need for a darkness test to reap the benefits of lead vehicle AEB in darkness. As part of this final rule, NHTSA is specifying minimum performance requirements for pedestrian avoidance in dark conditions. The agency believes that systems that can identify, and respond to, a pedestrian in the roadway at night could also possibly detect lead vehicle taillamps and other reflective surfaces that distinguish a vehicle from the surrounding visual landscape. The agency also believes a radar sensor will perform the same regardless of the lighting condition. As such, NHTSA believes an AEB system could be highly effective at classifying the rear of a lead vehicle in a dark condition, even without an explicit regulation requiring such performance. Only the daylight condition was proposed for lead vehicle AEB testing, and this sole lighting condition is maintained in this final rule.

Luminar, Forensic Rock, Consumer Reports, and Aptiv suggest the agency expand testing with additional overlaps (the measurement of deviation of the lead vehicle centerline and the subject vehicle centerline) for lead vehicle testing. Luminar stated that a 50 percent overlap in car-to-car scenario is used in both US and Euro NCAP testing and suggested that NHTSA should consider 50 percent overlap which, the commenter believed, is a common, achievable, car-to-car test scenario. Forensic Rock suggests expanding the testing to include a 25–50% overlap condition would ensure that the

[107] In instances where an FMVSS includes a range of values for testing or performance requirements, 49 CFR 571.4 states that the word any, used in connection with a range of values, means generally the totality of the items or values, any one of which may be selected by NHTSA for testing, except where clearly specified otherwise.

[108] These commenters included Luminar, Forensic Rock, Consumer Reports, Applied, Rivian, Advocates, Adsky and the Lidar Coalition.

performance of these systems included more than just pure collinear crash scenarios.

In response, NHTSA has not included test scenarios with an overlap less than 100 percent (although a tolerance on the travel path of the subject vehicle is included). A rear-end crash as defined in the FARS database is ''a collision in which one vehicle collides with the rear of another vehicle.'' [109] Even at the higher speeds used in testing, a change of the overlap during testing from 100 percent to 50 percent or 25 percent would result in only a marginal change in the position of the lead vehicle in the field of view of the sensors. The proposed overlap for lead vehicle AEB testing is consistent with NHTSA's NCAP test procedures for CIB and DBS, the IIHS test procedure, as well as UNECE Regulation No. 152.[110] The agency does not have the necessary information to demonstrate practicality and need for a regulation that adopts scenarios that include a broad range of overlap.

Some commenters suggest that NHTSA should consider adding additional testing scenarios from EuroNCAP, such as the head-on scenarios and left turn across path. Consumer Reports suggested NHTSA incorporate additional scenarios such as a curved travel path, scenarios involving challenges posed by environmental conditions, and circumstances in which the lead vehicle is revealed suddenly or is not aligned straight when in front of the subject vehicle.

In response, this final rule requires lead vehicle AEB systems that will prevent or mitigate rear-end crashes of light vehicles and is based on the research and other data demonstrating the efficacy and practicability of these systems. The data and technologies for test scenarios representing crashes other than a rear-end crash are not yet available to support possible inclusion in an FMVSS.

Applied stated that NHTSA should include additional scenarios and elements through virtual testing procedures. It stated that modeling and simulation technologies allow for a vehicle to be put through a much more expansive set of testing scenarios and elements than what are possible in real-world testing and may allow to vastly increase the number of tests that can be run creating a much greater pool of data to evaluate a vehicle.

In response, while virtual test scenarios involving modeling and simulation may be employed, and are employed, by manufacturers in developing lead vehicle AEB systems, such testing is not suitable for NHTSA's compliance testing of AEB systems at this time. Virtual testing has the potential to provide many benefits and advancements to motor vehicle safety. There are challenges, however, in using virtual assessments in agency compliance tests. The agency must be assured that the virtual scenarios it was running are representative of the real world and that the test results it obtained would be the same as those obtained in tests of an actual vehicle. Neither condition currently exists. Also, virtual test environments are reliable only if they have been appropriately validated. Right now, NHTSA does not have the research available to support the development of a simulator designed for the purposes of testing compliance with this rule. Though simulation testing is a method that NHTSA is very interested in from a research perspective, it is not yet an approach that is ready for NHTSA use in compliance testing.[111]

After considering the comments, this final rule adopts the three track test scenarios, which are lead vehicle stopped, lead vehicle moving and lead vehicle decelerating, as proposed in the NPRM.

2. Subject Vehicle Speed Ranges

The proposed speed ranges were selected based on the speeds at which rear-end crashes tend to happen, while considering two primary factors. The first factor is the practical ability of AEB technology to consistently operate and avoid contact with a lead vehicle. NHTSA's 2020 and 2023 research testing indicate that the selected speed ranges for the various scenarios are within the capabilities of current production vehicles. NHTSA proposed speed ranges to ensure AEB system robustness. To illustrate, during the agency's AEB research testing, two vehicles performed better at higher speeds (48 km/h or 30 mph) than at lower speeds (40 km/h or 25 mph) in the lead vehicle stopped tests, which suggests that a range of speeds should be used in FMVSS No. 127.[112]

The second factor is the practical limits of safely conducting track tests of AEB systems. Based on the available data, a majority of fatalities and injuries from rear-end crashes occur at posted speeds up to 97 km/h (60 mph). Due to the tendency of fatalities and injuries to increase as the vehicle travel speed increases, NHTSA proposed AEB system testing at the highest speeds at which NHTSA can safely and repeatably conduct tests. If a system does not intervene as required and the subject vehicle collides with the lead vehicle test device, it should do so in a manner that will not injure test personnel or demolish the laboratory's equipment and set-up.

Comments Seeking To Increase Testing Speeds To Increase Potential Safety Benefits

Many government entities, consumer interest groups, private individuals and others suggested that NHTSA consider exploring ways to increase test speeds.[113] Many suggested lead-vehicle AEB tests above 100 km/h (~60 mph) for the stopped lead vehicle and slower-moving lead vehicle scenarios, and 80 km/h (~50 mph) for the decelerating lead vehicle scenarios. These commenters point to the increased risk of crashes as well as fatalities and serious injuries resulting from crashes as speeds rise, and some believed that a requirement to meet higher test speeds is practicable. Forensic Rock stated that if a private accident reconstruction firm can find suitable track length to conduct

[109] *https://www-fars.nhtsa.dot.gov/Help/Terms.aspx#:~:text=Rear%2Dend%20Collision,The%20Rear%20Of%20Another%20Vehicle.* Accessed November 21st, 2023 at 3:22 p.m.

[110] National Highway Traffic Safety Administration (Oct., 2015), Crash Imminent Brake System Performance Evaluation for The New Car Assessment Program. Available at: *https://www.regulations.gov/document/NHTSA-2015-0006-0025;* National Highway Traffic Safety Administration (Oct., 2015), Dynamic Brake Support Performance Evaluation Confirmation Test for The New Car Assessment Program. Available at: *https://www.regulations.gov/document/NHTSA-2015-0006-0026;* Insurance Institute for Highway Safety (Oct., 2013), Autonomous Emergency Braking Test Protocol (Version I), Available at: *https://www.iihs.org/media/a582abfb-7691-4805-81aa-16bbdf622992/REo1sA/Ratings/Protocols/current/test_protocol_aeb.pdf;* and UN Regulation No 152—Uniform provisions concerning the approval of motor vehicles with regard to the Advanced Emergency Braking System (AEBS) for M1 and N1 vehicles [2020/1597] (OJ L 360 30.10.2020, p. 66, ELI: *http://data.europa.eu/eli/reg/2020/1597/oj*).

[111] There are also several practical challenges that prevent NHTSA from using virtual testing to determine compliance with the FMVSS. NHTSA's goal is to independently purchase vehicles available on the market without notification to the manufacturer (or anyone) that it is purchasing a particular vehicle. This helps make sure that the product that NHTSA is testing is one that consumers of that product would also purchase. If NHTSA were to obtain vehicles directly from manufacturers for compliance testing, NHTSA may not be as confident about the independence of its testing results. Also, AEB systems are proprietary systems. If NHTSA needs capabilities and access to the technicalities of the AEB system to conduct virtual testing, confidential business information issues may arise.

[112] *https://www.regulations.gov/document/NHTSA-2021-0002-0002.*

[113] These commenters included the cities of Philadelphia, Nashville, and Houston, the Richmond Ambulance Authority, DRIVE SMART Virginia, NACTOA, the Lidar Coalition, Consumer Reports, Forensic Rock, and Luminar.

high closing speed tests, NHTSA should be able to as well. NTSB stated that test scenarios be designed to best reflect real world operating conditions as NTSB investigations have shown there is a need to consider systems' performance in other crash-relevant scenarios including unusual vehicle profiles and configurations encountered in real-world conditions.

Agency Response

After considering the comments, NHTSA declines to increase the test speeds proposed in the NPRM. The agency explained in the NPRM that NHTSA proposed what it believed to be the highest practicable and reasonable testing speeds. Testing speeds are bound by important practicability matters and practical limitations, such as the safety of the testing personnel, vehicle and test equipment damage, and the repeatability of testing and test validity. Forensic Rock suggested adding equipment such as ''deer/cattle guards'' to the subject vehicle during testing. NHTSA believes such an approach is untenable because such equipment would still not protect testing equipment and would alter the ''real-world'' condition of the vehicle.

NHTSA limited the maximum test speeds for lead vehicle AEB to no more than a maximum 80 km/h (50 mph) speed differential. NHTSA is encouraged by Luminar and Forensic Rock's testing at speeds higher than the NPRM, but, with regard to Luminar's comment that the systems they tested performed at speeds up to 120 km/h, the agency's limit for the testing speed was determined based on factors including safety need and practicability, and not just on AEB performance. While NHTSA is currently researching other testing scenarios for AEB, the agency does not have the needed information regarding practicability and the need for a higher speed regulation to include a broader speed range at this time.

Comments Suggesting Different Approaches

Several commenters suggested NHTSA should take a hybrid approach and reduce speeds for a no-contact requirement while allowing contact at a higher speed. The Alliance, Toyota and others suggested NHTSA implement a hybrid approach that maintains no-contact requirements for lower-mid-range speeds while permitting compliance if acceptable speed reductions that reduce the risk of serious injury can be achieved in higher-speed scenarios. It stated that such an approach would align with the approach implemented by other international bodies, such as UNECE Regulation No. 152, where no contact is required up to 40 km/h and various levels of maximum impact speeds are allowed from 42 km/h up to 60 km/h.[114] A number of other commenters suggested reducing the range of testing speeds and allowing contact above certain testing speeds.[115]

The Alliance stated that the hybrid approach would ensure that vehicle speeds are reduced to a level where crashworthiness features can provide an additional layer of protection for reducing the severity of occupant and pedestrian injury outcomes by lowering the overall impact speed. Volkswagen provided an analysis, which it stated is not statistically significant, which showed that vehicles on the road today can protect their occupants from severe injuries of MAIS 3+ even with collision speeds up to 50 km/h. Toyota recommended an approach that vehicle-to-lead vehicle target contact be allowed ''at a speed low enough that the crash would be highly unlikely to be fatal or to result in serious injury.'' Honda also considered NHTSA's crash injury estimations for the risk of severe injury or fatality in frontal crashes to suggest a hybrid type approach.

Agency Response

The commenters support a hybrid approach where collision avoidance would be required only up to 42 km/h (26.1 mph) and speed reduction (a mitigated collision) permitted at speeds above 42 km/h (26.1 mph) during testing. NHTSA does not find this approach acceptable. The agency's intent is to prevent crashes at the highest practicable speeds and the proposed limits in testing speeds reflect this.

Using the speed limit as a proxy for traveling speed, the data presented earlier in this document show that about 60 percent of fatal rear-end crashes were on roads with a speed limit of 97 km/h (60 mph) or lower. That number is 73 percent for injury rear-end crashes and 78 percent for property-damage-only rear-end crashes. Out of the total rear-end crash population, only about 1 percent of fatalities, 5 percent of injuries and 7 percent of property-damage-only crashes happen where the speed limit is 40 km/h (25 mph) or less. If NHTSA were to require collision avoidance only for crashes up to 40 km/h (25 mph), in NHTSA's view only a fraction of fatalities and injuries would be avoided when so many more motorists could benefit. Such an outcome would fall short of meeting the need for safety, as meeting the proposed test speeds is practicable. As detailed in the research section, the 2023 Toyota Corolla Hybrid was able to avoid collision under all testing conditions up to the maximum proposed testing speed requirement for lead vehicle stopped and lead vehicle moving. That same vehicle, when tested for the lead vehicle decelerating scenario with a 12 m headway and 0.5g lead vehicle deceleration, was able to avoid collision in all trials when tested at 50 km/h and was able to avoid collision on two trials and incur impact speeds of approximately 5 km/h and below on the other three trials when tested at 80 km/h (50 mph). If NHTSA were not to require collision avoidance during testing at speeds up to 100 km/h (62 mph), the majority of fatal rear-end crashes would not be prevented.

NHTSA is providing a five-year lead time to push development of the technology while providing time to foster the evolution of it to achieve AEB's life-saving potential. Four out of the six vehicles tested avoided collision during agency testing at 50 km/h subject vehicle to 50 km/h lead vehicle and 12 m and the other two avoided in four out of the five trials. Considering that current AEB systems seem somewhat detuned at higher speeds because they were not designed to this requirement, the agency is encouraged that when engineered to meet this requirement, AEB will be able to avoid collision in a similar fashion as they do now under the 50 km/h condition.

The injury curves and thresholds provided by the commenters show that below 40 km/h (25 mph), there is a reduced probability of AIS3+ injury. With AEB, there is the potential to prevent the crash from occurring in the first place, *i.e.,* to completely mitigate the risk of injury. The technology has proven capable of avoiding collisions during testing at higher speeds. With the potential of AEB technology, its rapid evolution, and the significant lead time this final rule is providing to allow for maturation and deployment of AEB, NHTSA has decided to maintain the no-contact requirement and speed limits at the levels proposed in the NPRM.

As another approach, Honda suggested to test only at what they state are worst case scenarios that pose the highest risk of injury (*i.e.,* impact relative speed) and present the most challenging situations for AEB systems to react quickly (*i.e.,* time to impact). Honda stated that after evaluating

[114] *https://unece.org/transport/documents/2023/06/standards/un-regulation-no-152-rev2*. Other commenters supported harmonizing with UNECE Regulation No. 152, including ASC, Ford, Mitsubishi, and Nissan.

[115] These commenters included HATCI, Nissan, ZF, and Aptiv.

various combinations within the proposed headway distance and lead vehicle deceleration ranges, the worst-case scenarios are for impact relative speed of 72 km/h, time to collision (TTC) of 2.1 sec with a lead vehicle deceleration of 0.5 g, at both the 12 m and 40 m headway distances at 50 or 80 km/h.

In response, NHTSA does not believe that ''worst case'' scenario testing is appropriate for this standard in this final rule. In past NHTSA tests, vehicles sometimes avoided contacting the vehicle test device at higher speed tests but contacted it at lower speeds. A range of tests is necessary to better ensure satisfactory performance of the systems in the real world.

Some Commenters Suggest Reduced Speeds and Repeat Trials To Avoid What They See as Potential Negative Consequences

A number of commenters believed that having to meet the higher end of the proposed speed range will increase the likelihood of negative consequences. Several commenters believed that the higher end of the proposed speed range will increase the likelihood of false positives.[116] Porsche and Volkswagen stated that doubling the relative velocity at which no contact is required, as compared to UNECE Regulation No. 152, may impact the robustness of the system in real-world performance, potentially leading to increased instances of premature or unnecessary braking in the real-world. Aptiv stated that due to the possibility of false positives, NHTSA should reduce testing speeds to 50 km/h (31 mph) and allow repeat trials. Mobileye stated that the proposed requirement will necessitate hardware updates or replacement, and preferred a speed reduction requirement, based on a 2 out of 3 test runs. HATCI stated that NHTSA should follow the AEB voluntary commitment requirements.[117]

Agency Response

One reason the commenters requested lowering the upper speed range for a no-contact requirement was the concern that false activations would increase. In the NPRM, NHTSA stated that the proposed testing requirements are practicable and are intended to avoid and mitigate the most crashes. In the NPRM, NHTSA expressed that AEB systems are undergoing rapid advancement and have been able to achieve collision avoidance at higher testing speeds without major updates. Since the publication of the NPRM, NHTSA research has confirmed that a vehicle (the 2023 Toyota Corolla Hybrid) was able to avoid collision under all testing conditions up to the maximum proposed testing speed requirement for lead vehicle stopped and lead vehicle moving. That same vehicle, when tested for the lead vehicle decelerating scenario with a 12 m headway and 0.5 g lead vehicle deceleration, was able to avoid collision in all trials when tested at 50 km/h and was able to avoid collision on two trials and incur impact speeds of approximately 5 km/h and below on the other three trials when tested at 80 km/h (50 mph).

This vehicle's ability to pass these tests demonstrate that the proposed requirements are practicable and the technology is still evolving. As stated in the NPRM, the expectation for the tested AEB production systems (which were not designed to meet these requirements) was not that they would pass all trials; rather, it was to inform the agency on the practicability of the proposed testing speeds. The fact that a current AEB system is already capable of meeting the AEB requirements confirms the agency's assumption that current AEB systems can be further developed within the lead time provided.

Another area of concern expressed by the commenters was sensor range performance. Honda and Bosch both had concerns about requiring no contact when testing at higher speeds as current AEB systems sensor range makes it difficult for the system to discern objects far enough to achieve no contact and mitigate false positives. In previous agency testing that informed development of the NPRM, for the vehicle that performed the best—according to the publicly available information from the manufacturer—the upgrades to the AEB system from the previous generation included, among others, improved sensor range.[118] As shown by the evolution of the Toyota system, and based on the testing results from the other vehicles which also show significant advancement in collision avoidance, NHTSA is confident that current systems, given sufficient development time, can be engineered to avoid contact and mitigate false positives in a similar manner as the Toyota system.

The request for further development time was raised by the majority of industry commenters, and, as discussed later in this preamble, NHTSA agrees and is providing more time to meet this final rule. Based on the comments received, it seems that the main solution currently employed by manufacturers to mitigate false positives is to detune the system at higher speeds (consistent with current UNECE requirements). Euro NCAP, while not a regulation, employs similar testing at similar speeds as proposed in the NPRM (and adopted by this final rule), and many vehicles achieve a full score on Euro NCAP testing due to their collision avoidance capabilities. This information further reinforces NHTSA's assessment that the proposed testing speeds are practicable and deployable in the real world with sufficient lead time.

Ford stated that harsh braking to avoid high speed collisions can result in rear end collisions based on an internal controllability study with randomly selected drivers in Germany. Based on that study Ford stated there is an increase in rear end collisions resulting from AEB activation above differential speeds of 60 km/h (37.5 mph).

In response, NHTSA was unable to find this study as Ford did not provide any data on it. Thus, NHTSA was unable to evaluate the relevance of Ford's statement to the current rule. The agency observes, however, the proposed requirements do not require hasher braking than currently demonstrated by vehicles compliant with FMVSS No. 135. Further, if all vehicles were equipped with AEB systems conforming to this final rule, it is plausible that no crash would happen.

Comments About Increased Costs as New Hardware is Needed

Mobileye stated that for the stopped lead vehicle, the majority of AEB systems in vehicles today will need a new safety strategy and may need hardware updates/replacements. Therefore, Mobileye states, the assumption that all vehicles have the necessary hardware is not correct.

Agency Response

In response, NHTSA concurs that the cost estimates in the NPRM underestimated the incremental hardware costs associated with this final rule. Accordingly, this final rule has

[116] These commenters included, ASC, Mobileye, Bosch, Ford, Mitsubishi, Honda, the Alliance, Porsche, Volkswagen, HATCI, Rivian, Bosch, and Aptiv.

[117] The voluntary commitment included automatic braking system performance (CIB only) able to achieve a specified average speed reduction over five repeated trials when assessed in a stationary lead vehicle test conducted at either 19 or 40 km/h (12 or 25 mph). To satisfy the performance specifications in the voluntary commitment, a vehicle would need to achieve a speed reduction of at least 16 km/h (10 mph) in either lead vehicle stopped test, or a speed reduction of 8 km/h (5 mph) in both tests.

[118] *https://www.jdpower.com/cars/shopping-guides/what-is-toyota-safety-sense,* accessed November 13, 2023.

adjusted the estimates presented in the NPRM to include the costs associated with software and hardware improvements, compared to the baseline condition. Incremental costs reflect the difference in costs associated with all new light vehicles being equipped with AEB with no performance standard (the baseline condition) relative to all light vehicles being equipped with AEB that meets the performance requirements specified in this final rule. The Final Regulatory Impact Analysis (FRIA) provides a detailed discussion of the benefits and costs of this final rule.

Comments About the Effect of Test Speed on Evasive Steering

When a driver is alerted to an impending crash, the driver may manually intervene by, for example, applying the vehicle's brakes or making an evasive steering maneuver, to avoid or mitigate the crash. Several commenters believed that the agency should ensure that all final test conditions (especially at higher test speeds) would preserve steering intervention or other intentional driving behavior regarding the TTC intervention times.

A number of commenters believed that at higher testing speeds, AEB could interfere with evasive steering maneuvers.[119] Honda stated that AEB should only intervene when a collision is otherwise unavoidable and is designed to intervene as late as possible to mitigate injury and not interfere with evasive or normal driver steering maneuvers. Honda stated that differentiating between those situations where steering is more appropriate than emergency braking is critical when considering the unintended consequences of AEB. Honda believed that, under the proposed speeds, AEB intervention will be forced to occur before the driver might steer, hindering the driver's appropriate and intended response in real-world higher speed scenarios.

The Alliance stated that, based on a NHTSA study,[120] the time required to avoid impact by steering or braking are equal at approximately 35 kph and 0.61 seconds and that above 35 kph, avoidance though braking begins to require increasingly more time than steering. Drivers are generally more likely to initiate braking to avoid striking an object at speeds below 44 kph and are more likely to initiate steering to avoid impact above 44 kph. The Alliance stated that the driver will typically initiate their maneuver before 1.7 seconds TTC and therefore, any ''no-contact'' requirement for AEB at higher speeds will necessitate activating AEB before the driver has an opportunity to steer around the threat when a steering maneuver would be more effective. Similarly, Toyota stated that NHTSA should define a maximum speed for the lead vehicle AEB testing with no manual brake application, of no greater than 60 km/h for the ''no-contact'' requirement, due to the potential effect of evasive steering and the timing of AEB activation.

Agency Response

NHTSA has considered the comments but does not find the arguments relating to evasive steering compelling. AEB intervention is a last resort crash avoidance maneuver, and it does not seem reasonable to assume that a driver who is inattentive until moments before a crash will reengage and be able to perform a safe steering maneuver that would not jeopardize other traffic participants. The information provided by Honda, Toyota, and the Alliance seem to consider only the timing required for a vehicle to brake to a complete stop versus the timing of a steering maneuver, without considering any other factors. Such factors as vehicle dynamics, traffic conditions, and traffic participants all influence the safety benefit of a steering avoidance maneuver. While NHTSA does not encourage aggressive and unsafe driving behavior as shown in that example, we do note that because the test procedures involve manual braking, disengagement of AEB cannot happen solely due to brake application. Nothing in our standard, however, requires a manufacturer to suppress steering. A manufacturer, outside of the testing requirements, may elect to detune or disengage the AEB system based on an emergency steering maneuver as long as they meet all the AEB requirements.

The type of roadway (two lane, divided, interstate) is an important factor in assessing whether a steering maneuver is appropriate, as is the traffic on such roadways. It seems unreasonable to expect that, except for very specific situations such as when an adjacent lane exists and is empty, a disengaged driver could perform any type of steering maneuver safer than stopping in the lane.

In normal driving situations, rear end crashes frequently happen in heavy traffic where crash avoidance maneuvers from automatic or manual steering could cause the vehicle to either depart the road, collide with a vehicle in the adjacent lane, or, on an undivided two-lane road, cause a head-on frontal crash. Further, research referenced by Porsche in their comments shows that overwhelmingly, drivers either brake, or brake and steer, when presented with a surprise obstacle catapulted from the side.[121] In this research, when the obstacle was presented to the drivers at a TTC of 1.5s, with the adjacent lane free of obstacles and the drivers had the opportunity to avoid a collision by steering alone, 43 percent of participants attempted to avoid by braking alone. The other 57 percent of participants tried to avoid the collision by braking and steering, while no participant tried to avoid contact by steering alone.

At a TTC of 2.0 s, 46 percent of participants tried to avoid by braking alone, 38 percent by braking and steering, and 15 percent by steering alone, while at a TTC of 2.5s 72 percent of participants tried to avoid by braking only, 14 percent tried to avoid by braking and steering, and 14 percent tried to avoid by steering alone.

This research found that only at TTCs later than two seconds did drivers attempt to avoid only by steering alone, which suggests that drivers were not comfortable steering to avoid the presented object at the speed they were traveling without braking, further reinforcing the agency's assertion that braking in lane is appropriate. Looking at these results and considering that this research was performed with a surprise object catapulted from the side (which induces a preference for drivers to avoid by steering), it is clear that drivers are more inclined to brake in an emergency. Additionally, drivers brake even as they attempt a steering maneuver, which can lead to unstable vehicle dynamics. This serves to reinforce the agency's findings that a brake in the lane maneuver, even if it occurs early, before a TTC of 1.5s, is the safest, most appropriate, maneuver.

The other situation where steering may be more appropriate, according to the commenters, is an engaged driver who consciously decides to avoid by steering. The steering avoidance maneuver by an engaged driver as shown by HATCI in their comment would still present a higher safety risk than a brake in the lane maneuver. In that example, a vehicle avoids the lead vehicle by cutting in front of a vehicle

[119] These commenters included ASC, Mobileye, Bosch, the Alliance, HATCI, Ford, Mitsubishi, Porsche and ITS America.

[120] *Forward Collision Warning Requirements Project Final Report—Task 1 (DOT HS 809 574)—January 2003.*

[121] Emergency Steer and Brake Assist—A Systematic Approach for System Integration of Two Complementary Driver Assistance Systems (Eckert, Continental AG, Paper Number 11–0111), *https://www-esv.nhtsa.dot.gov/Proceedings/22/files/22ESV-000111.pdf.*

on the adjacent lane. NHTSA fails to understand how such a maneuver is safe for any of the vehicles involved, especially considering the likelihood that other vehicles would be in the adjacent lanes. A subject vehicle darting out of its lane into an adjacent lane could result in a different type of crash.

3. Headway

Comments

A key test parameter for the lead vehicle AEB tests is the initial headway [122] between the subject vehicle and the lead vehicle. Several vehicle and equipment manufacturers opposed the proposed headway conditions (12 m at 80 km/h) in decelerating lead vehicle AEB tests.[123] They stated that the proposed headway requirement is not practical because the short headway values at high relative speeds go beyond the capabilities of current AEB systems. Volkswagen, Porsche, Rivian, and others argued that the low headway conditions at high relative speeds may increase false positive rates, leading to phantom braking because earlier braking means the system looks further ahead, both in space and in time. (Hence, commenters stated, the probability for a collision is estimated at a lower accuracy value and this may lead to a false positive activation.)

Many commenters believed the 12 m proposed headway at 80 km/h is a very close following distance that would equate to an unsafe following distance in the real world and that AEB systems are not designed to account for this type of ''misuse'' by the driver. In addition, they believed that compliance with a no-contact requirement would require immediate emergency braking at maximum deceleration, which, the commenters stated, would result in an uncontrollable safety hazard for following traffic. Volkswagen and Porsche suggested removing the 12 m headway at the 80 km/h scenario from the decelerating lead vehicle tests and aligning with the requirements of UNECE Regulation No. 152.[124] Similarly, Mitsubishi suggested 23 m as the minimum headway because the proposed minimum headway distance (12 m) is considered close enough to issue an FCW even with minimal deceleration of the subject vehicle. MEMA and Bosch suggested a headway greater than 16 m and a time gap greater than 0.2 seconds at 80 km/h to create a more representative test scenario that resembles a constant following distance. Mobileye stated that the headway of the 12 m in decelerating lead vehicle test scenario at 80 km/h is around 0.5 s which, the commenter believed, was not realistic because research data showed that the median headway time across 10 different sites was 1.74 s.

Agency Response

The agency disagrees with Volkswagen and other manufacturers that the lower bound (*i.e.,* 12 m) of the headway range is not practicable for the current AEB systems at a high speed (*e.g.,* 80 km/h). NHTSA discussed in the NPRM that 4 out of 11 vehicles in the agency's 2020 AEB research met the no-contact requirement of this rule when the subject vehicle and lead vehicle were traveling at 72.4 km/h (45 mph) with an initial headway of 13.8 m (45 ft). The deceleration of the lead vehicle was 0.3 g. This research also included decelerating lead vehicle testing at 56.3 km/h (35 mph) with a deceleration rate of 0.5 g.

In the NPRM, NHTSA tentatively concluded that the current lead vehicle AEB systems would be able to meet the most stringent headway requirement (*i.e.,* 12 m) if their perception software was properly tuned for the higher lead vehicle deceleration (0.5 g). The agency's MY 2023 AEB research supports this.[125] The test results demonstrated that one of the six vehicles was able to meet the requirements of this standard in all five trials at 80 km/h with the initial headway of 12 m and the lead vehicle deceleration of 0.5 g. Another vehicle was also able to meet the test requirements in 2 out of 5 trials for the same test speeds.

In their comment, Honda stated that the worst-case scenarios for impact relative speed (72 km/h) are accomplished with a lead vehicle deceleration of 0.5 g at the 12 m headway distance. Given the performance of these two vehicles in the most difficult testing scenario, NHTSA continues to believe that the headway specifications of this final rule—any distance between 12 m (39.4 ft) and 40 m (131.2 ft)—are within the capabilities of the AEB systems designed to comply with this final rule.

As for the potential increase of false positive rate raised by Volkswagen, Porsche and Rivian, false positive activation that causes an unreasonable risk to safety is a defect issue. Vehicle manufacturers are responsible for mitigating and resolving any defects in their vehicle products. Here, the concern is based on a hypothetical situation where a vehicle at a high speed with a small headway (*e.g.,* 12 m) may prematurely activate the AEB system—forcing initiation of early braking—when there is not a true risk of an imminent collision. At 80 km/h (50 mph), a headway of 12 m is uncomfortably close to a crash imminent situation and the agency feels strongly that it is difficult even for an attentive driver to react properly to avoid a crash in this scenario, especially with a lead vehicle braking above 0.3g. It is up to manufacturers to design their AEB systems to deal with situations where the driver is following close to the vehicle in front of it, and the lead vehicle decelerates between 0 and 0.3 g. They must determine what is a false positive and what is an actual positive.

As for replacing the current range requirements for headway with discrete values, NHTSA disagrees with Honda and Volkswagen that the range requirements require infinite number tests and cause unreasonable test burden to manufacturers. The agency noted in the NPRM that the use of a range of potential values allows NHTSA to ensure that AEB system performance remains consistent, as conditions—in this case headway—vary within the bounds of the range. NHTSA has observed that some lead vehicle AEB systems performed well under high speed or shorter headway scenarios, but did not perform as well under lower speed or longer headway scenarios. This type of performance inconsistency is why the agency proposed a range of values, and not just discrete values.

The current range headway provides manufacturers an understanding of the performance the FMVSS requires. Manufacturers have the ability and flexibility to decide how they can certify that a given AEB system complies with the requirements contained in this final rule. This includes the number and types of tests needed to ensure that an AEB system works throughout the proposed range. The agency is providing notice of how we test a vehicle's compliance. For these reasons, NHTSA believes that the headway range requirements do not cause an unreasonable test burden.

Accordingly, NHTSA declines to amend the range of headway specifications in decelerating lead vehicle AEB tests. This final rule adopts that the headway specifications in

[122] Headway refers to the distance or interval of time between vehicles moving in the same direction on the same route.

[123] These commenters included Volkswagen, Porsche, Mitsubishi, Rivian, Honda, MEMA, Bosch, and Mobileye.

[124] That regulation currently requires full collision avoidance up to 40 km/h relative speed between the subject and lead vehicle.

[125] NHTSA's 2023 Light Vehicle Automatic Emergency Braking Research Test Summary, available in the docket for this final rule (NHTSA–2023–0021).

decelerating lead vehicle AEB tests to include any distance between 12 m (39.4 ft) and 40 m (131.2 ft) as proposed in the NPRM.

4. Lead Vehicle Deceleration

The decelerating lead vehicle scenario is meant to assess the AEB performance when the subject vehicle and lead vehicle initially are travelling at the same constant speed in a straight path and the lead vehicle begins to decelerate. NHTSA's proposed lead vehicle AEB tests included parameters for the deceleration of the lead vehicle.

Honda expressed concern that the proposed rule included a broad range of parameters for lead vehicle deceleration (ranging from 0.3 to 0.5 g). It further stated that testing a theoretically infinite number of combinations within the proposed range is impractical. Honda suggested that the proposed range of deceleration values should be replaced with discrete nominal test values for lead vehicle AEB deceleration tests.

In response to Honda, NHTSA believes that the targeted average deceleration is best represented by a bounded range, rather than a discrete value, to better evaluate vehicle performance. During agency testing, NHTSA has observed vehicles that may perform well at the upper and lower bounds of a performance range, yet inconsistently perform in the middle of a performance range. The agency believes that specifying a bounded range of 0.3 g to 0.5 g will better ensure consistent performance of AEB systems in real world situations than if a discrete value were specified. Further, the test procedures of this rule provide information regarding how the agency will conduct tests. Manufacturers have the flexibility to certify the compliance of their vehicles using reasonable care, and are not required to conduct testing as the agency does if the vehicle passes when tested by NHTSA as specified in the standard. Therefore, this final rule adopts the average deceleration range proposed in the NPRM.

Humanetics commented that the provision related to ''targeted deceleration'' should state that the deceleration is maintained until the speed is below a target value (such as 1 km/h) and that the regulatory text ''250 ms prior to coming to a stop'' in proposed S7.5.3a should be replaced with ''the lead vehicle speed is reduced to 1 km/h.''

NHTSA disagrees with the comment. When determining the targeted average deceleration, the agency has specified that the targeted deceleration will occur within 1.5 sec of lead vehicle braking onset, giving the lead vehicle time to reach the desired deceleration. As the vehicle comes to a stop, the acceleration profile becomes noisy and is not reflective of the actual deceleration observed through most of the test. Thus, the agency proposed that the last 250 milliseconds (ms) of the vehicle braking before coming to a stop are not used in the calculation of the targeted average deceleration. Changing this threshold to be a speed measurement, as suggested by Humanetics, would change the end of test parameter to allow for contact and would not address the noise in the deceleration as the vehicle comes to a stop. (This metric is consistent with how NCAP currently performs AEB testing.) NHTSA concludes that the metric does not need additional clarification and thus declines to replace the current time-based provision with a speed-based protocol.

5. Manual Brake Application

NHTSA proposed lead vehicle AEB performance tests that included parameters for the manual brake application made to the subject vehicle.

NHTSA received several comments from vehicle and equipment manufacturers on the provisions. Porsche and Volkswagen stated that NHTSA should provide additional clarity specific to the brake robot application, particularly regarding proposed S10 specific to the set-up and calibration of the braking robot and the rate of brake pedal application. Hyundai suggested removing the manual braking tests and replacing them by a statement in FMVSS No. 127 to the effect that, ''A driver's manual activation of the brake pedal shall not impair the operation or effectiveness of AEB.'' ASC sought further clarification regarding the manual brake application profile. Humanetics believed that the tolerance was too tight in proposed S10.4 that brake pedal force is to be maintained within 10 percent of the commanded brake pedal force. Humanetics encouraged NHTSA to adopt a wider tolerance, such as allowing an applied force within 25 percent of the commanded force, while also allowing shorter duration forces (less than 200 ms) that may exceed the 25 percent tolerance.

This final rule adopts the NPRM's proposed specifications for the manual braking conditions. It also includes a third brake control option that a manufacturer may choose.

The agency disagrees with Hyundai that the purpose of the manual braking conditions can be achieved by the suggested statement. The tests with manual braking application are different from the lead vehicle AEB tests without manual braking. First, manual braking tests are conducted at a higher range of subject vehicle speed, at any subject vehicle speed between 70 km/h (43 mph) and 100 km/h (62 mph) for both the stopped and slower-moving lead vehicle scenarios, than that of corresponding AEB tests without manual braking application. Second, the tests with manual braking application represent two different real-world situations. The first represents a driver that reacts to the FCW and re-engages in the driving task by applying the brake (although with insufficient force to prevent a collision). In this case, the vehicle must be capable of recognizing that the driver has failed to provide adequate manual braking and supplement it with automated braking force. The second represents a driver who re-engages very late in the AEB event. The test ensures that the act of late manual braking does not disrupt or disengage crash imminent braking functionality.

The language suggested by the commenter considers only this second condition and not the first. Additionally, Hyundai did not provide a metric for ensuring that this performance could be met using their proposed language. Therefore, NHTSA declines to remove the manual braking test conditions in the lead vehicle AEB tests of this final rule.

Regarding the specifications for the braking robot, the agency notes that both Porsche and Volkswagen requested more detail but neither explained the issues they faced, or what is needed in terms of additional information. Both manufacturers have experienced braking robots in other AEB testing. In the proposal, NHTSA stated that either a displacement braking controller or a hybrid braking controller (braking robot) could be used, at the manufacturer's discretion, and proposed requirements for the performance of these two styles of controllers. Additionally, the agency imposed no limitations on how manufacturers can self-certify. Thus, manufacturers, who have the best knowledge of their AEB systems, are free to choose a braking method (type of braking controller, human test driver, etc.) that best serves their needs to certify their vehicles. As Porsche recognized, various brake robots are available with different specifications. A manufacturer can easily select the one that is most appropriate for testing its AEB system. Therefore, NHTSA concludes it is unnecessary to specify a single brake controller or braking robot.

ASC sought further clarification regarding the tests that require manual brake application on the manual brake

application profile. It specifically highlighted the time for driver reaction, movement of foot brake pedal application, and build system pressure. They also highlighted that 1.2 seconds after an FCW would be a typical driver response time according to Euro NCAP.

As stated in the proposal, brake pedal application onset occurs 1.0 ± 0.1 second after the forward collision warning onset, thus, the driver response time is approximately one second. The agency does not have data showing that a reaction time of 1.2 is more appropriate. Specifics such as the movement of foot brake pedal application and system pressure are best not stipulated as absolutes, as they may change based off each brake system and in-vehicle brake controller. The agency believes it has provided sufficient notice for manufacturers to understand how NHTSA will test.

ASC also sought information on how the agency determines brake pedal application onset. NHTSA does not believe that specifying a minimum brake pedal displacement, along with a minimum level of force applied to the pedal is necessary. To displace the pedal at all requires a minimum amount of force. The agency believes that 11 N (2.5 lbf) of force is small enough to be easily achieved by a driver or controller, and large enough to show intent to brake. Thus, the agency is not adopting a change to the brake pedal application onset.

ASC highlighted that NHTSA had not considered braking systems using force feedback. The agency agrees that a force only feedback controller will provide another useful method of brake application. As such, the final rule includes this third brake control option that a manufacturer may choose. It is substantially similar to the hybrid controller with the commanded brake pedal position omitted, leaving only the commanded brake pedal force application. The force feedback brake pedal application applies the force that would result in a mean deceleration of 0.4 g in the absence of AEB activation.

6. Testing Setup and Completion

The NPRM proposed that the subject vehicle and lead vehicle speeds are maintained within 1.6 km/h, the travel paths do not deviate more than 0.3 m laterally from the intended travel path, and the subject vehicle's yaw rate does not exceed ±1.0 deg/s. MEMA and ASC suggested that the lane positioning requirements should be harmonized with UNECE Regulation No. 152, *e.g.,* 0.2 m not 0.3 m permitted lateral variance. Humanetics suggested that NHTSA use more strict tolerances for the subject vehicle, to increase repeatability. Humanetics also stated that as the yaw rate is quite a noisy signal, a filter should be used for the lead and subject vehicles. Humanetics further suggested that the agency should consider currently accepted tolerances to test speeds and other test parameters in defining these FMVSS tests.

In response, NHTSA disagrees with the commenters that a tighter tolerance is needed. The agency's specification is in line with previous NHTSA testing. As for requiring a smaller tolerance for vehicle speed and providing additional tolerances for a target carrier, the agency disagrees with Humanetics that the tolerance specified is excessively large for attaining repeatable and reliable testing. NHTSA does not have any data showing that manufacturers cannot meet these tolerances, nor that the tolerances proposed induce testing failures. Additionally, requiring a tighter tolerance is not representative of expected on road conditions. Accordingly, the agency does not see value in providing tighter tolerances.

NHTSA also notes that the agency proposed tolerances for where the lead vehicle will be positioned and operated during the performance tests. NHTSA is concerned that adding more tolerances to the carrier system that drives the vehicle test device would overly constrain the testing set up. Lastly, ISO 19206–7 is in draft form and is yet to be finalized. As such, it would be premature to incorporate the document into this final rule. Given the above, the agency declines to change lane positioning requirements or adopt additional tolerancing.

Regarding test completion, the NPRM proposed that, ''The test run is complete when the subject vehicle comes to a complete stop without making contact with the lead vehicle or when the subject vehicle makes contact with the lead vehicle.'' The Alliance stated that, for the slower-moving vehicle scenario, imposing a full braking requirement may not be appropriate if the target/lead vehicle were to continue to move (or if a stopped vehicle were to move again under real-world conditions). The commenter suggested that test completion be defined as ''the instance when the subject vehicle speed is equal or less than the lead vehicle speed without making contact with the lead vehicle, or when the subject vehicle makes contact with the lead vehicle.''

In response, NHTSA notes that the NPRM addressed the Alliance's concern in the proposed test procedures in proposed S7.4.4. This final rule adopts the proposed test completion criteria—''test run is complete when the subject vehicle speed is less than or equal to the lead vehicle speed''—for slower moving lead AEB tests as proposed.

Bosch suggested NHTSA consider setting parameters to define a ''valid run'' with respect to pedal and steering inputs to maintain tolerance on approach. Bosch stated that they encountered testing cases where an overly narrow definition of the calibration tolerances of the robot has interfered with the system reaction. Bosch also commented that, depending on the robot mode and type of vehicle brakes utilized, interference with the ADAS systems may occur. Bosch suggested the adoption of tolerances outlined in UNECE Regulation No. 152 for performance testing, with the aim of promoting standardized and realistic evaluations of automotive safety systems.

In response to Bosch's suggestion to define what a valid run is, NHTSA highlights the position and speed specifications for testing as stated in the NPRM that beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs. Additionally, the subject vehicle heading is maintained with minimal steering input such that the travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s. Bosch provided no additional information as to the inadequacy of NHTSA's proposed specifications for how the lead vehicle and subject vehicle respond prior to subject vehicle braking. Additionally, Bosch did not identify specific inadequacies in the braking controllers specified for use with manual braking

As for the proposed triggering times/TTCs (related to the ''beginning of tests''), the ASC stated that different test procedures in the NPRM specify different triggering times/TTCs (*e.g.,* three (3) seconds in S7.5.2, four (4) seconds in S8.2). ASC suggested that the trigger time period be standardized for all test scenarios.

The agency disagrees with this TTC suggestion. NHTSA selected appropriate test procedures, including triggering times, for each test scenario based on its unique features. For example, a three-second triggering time in a decelerating lead vehicle AEB test (S7.5.2) is selected to provide sufficient time to align a subject vehicle with a lead vehicle and to set a proper headway between the vehicles. On the other hand, a four-second triggering time in a PAEB test (S8.2) is selected to estimate an initial headway between a subject vehicle and

a pedestrian surrogate. As such, these triggering times represent unique features of two different tests. There are reasons not to standardize a triggering time to use across all lead vehicle and pedestrian AEB test scenarios.

ASC sought clarification on the accelerator pedal release process when the vehicle cruise control is active. In response, as stated in the NPRM, when cruise control is active the pedal release process is omitted as the accelerator pedal is already released. The agency expects an equivalent level of crash avoidance or mitigation regardless of whether cruise control is active.

7. Miscellaneous Comments

Mobileye stated that in some cases of target deceleration, the robot deceleration will be enough, or close enough, to avoid a collision. Mobileye stated that, in cases where the collision speed is very small, the AEB system can cause a nuisance event by a slight modification of the braking power by the driver. Mobileye suggested a more deterministic approach for these test scenarios which will result in a collision speed above 10 kph when using the robot 0.4 g deceleration.

In response, NHTSA does not specify the level of deceleration that the AEB system needs employ to safely bring the vehicle to a stop. In fact, during testing, the agency has observed that while some vehicles employ late and harsh braking as described by Mobileye, more refined AEB systems do not perform in such a manner.[126] As shown by Mobileye, to resolve the example they provided, only a slight additional deceleration, to further reduce the subject vehicle speed of 6.3 km/h, is needed to avoid the collision without harsh braking.

Bosch suggested NHTSA consider employing the term ''stationary vehicle'' as used in the UNECE Regulation No. 152 specification, instead of ''stopped,'' to promote uniformity and consistency in automotive safety terminology with existing standards and specifications. Bosch believed the distinction is crucial for some AEB systems as ''stopped'' vehicle implies that the vehicle was in motion immediately before the sensors have detected the Vehicle Under Test (VUT). Bosch suggested using the term ''stationary'' instead of ''stopped'' to align with existing standards and avoid any potential misinterpretations about the VUT as moving.

NHTSA does not agree with Bosch that the term ''stopped lead vehicle'' should be amended to ''stationary vehicle.'' The standard's test procedures clearly specify how the lead vehicle test device is placed (see, S7.3.2 of the proposed regulatory text) (''the lead vehicle is placed stationary with its longitudinal centerline coincident to the intended travel path'') and does not lend itself to potential misinterpretations. The term stopped, used in this requirement, is consistent with the agency's practices in previous AEB research and in the current U.S. NCAP.

NHTSA received several comments regarding test speeds as applied to vehicles equipped with ADS. The Alliance, AVIA and Zoox suggested that compliance testing be limited to the maximum speed that an ADS-equipped vehicle can achieve within its operational design domain. AVIA commented that some ADS-equipped vehicles have top speeds below those required in the Lead Vehicle AEB Collision Avoidance test parameters, and therefore suggested modifying the test parameters such that they can be met when an ADS-equipped vehicle operates at its highest speed if that speed is lower than the originally proposed subject and lead vehicle speeds. Zoox commented that an ADS may ''refuse'' to drive at 80 km/h at a following distance of 12 m or at 80 kph between two parked cars because this behavior does not align with its more conservative driving parameters.

In response, by including a maximum speed of 90 mph in this final rule, NHTSA is not requiring that manufacturers design their vehicles to be capable of driving 90 mph. Similarly, NHTSA is not requiring that Zoox design its ADS to operate at 90 mph. Instead, NHTSA may test the vehicle at the maximum speed the vehicle can achieve in its operational design domain. However, if the speed limitation in Zoox's vehicles are solely due to ADS programming and the vehicle itself is not speed limited, then Zoox must certify compliance to all speeds up to the maximum speed its vehicles are capable of being driven. As an example, if Zoox's ADS is programmed to drive at speeds up to 45 mph, but the vehicle has functionality that would allow it to be driven at speeds up to 90 mph, then Zoox must certify that AEB operates as required by this final rule at speeds up to 90 mph.

Regarding proposed subject vehicle specifications, an anonymous commenter stated that they found some of the procedures and criteria to be unclear or confusing in the NPRM. They stated that NHTSA should provide more diagrams and figures to clarify the test procedures and criteria.

In response, NHTSA believes that the NPRM provided sufficient information to the public to understand the requirements of the proposed standard. The agency included many figures, diagrams, and tables, that highlighted and explained key information. These figures, coupled with the detailed testing scenarios and test track conditions, adequately describe the rulemaking and the performance NHTSA is requiring by issuing FMVSS No. 127.

I. Procedures for Testing PAEB

This section describes the pedestrian AEB performance tests adopted by this final rule. After considering the comments to the NPRM, NHTSA has adopted the proposed procedures tests with a few minor revisions to some parameters and definitions, to clarify details of the test procedures. Importantly, NHTSA has increased the lead time to meet the requirements by providing a five-year lead time.

This section responds to the comments and explains NHTSA's reasons for adopting the provisions set forth in this final rule. For the convenience of readers, a list of the test specifications can be found in appendix B to this final rule preamble.

The pedestrian AEB performance tests require AEB systems to provide a forward collision warning (FCW) and automatically apply the service brakes at all forward speeds above 10 km/h (6 mph) to avoid an imminent collision with a pedestrian.[127]

The test scenarios required for PAEB evaluation fall into three groups of scenarios based on how NHTSA will apply the pedestrian test device—crossing path, stationary and along path. For each test conducted under the testing scenarios, there are the following provisions within those testing scenarios: (1) pedestrian crossing (right or left) relative to an approaching subject vehicle; (2) subject vehicle overlap (25% or 50%); [128] (3) pedestrian obstruction (Yes/No); and, (4) pedestrian speed (stationary, walking, or running) (V_P).

NHTSA will select further parameters from a subject vehicle speed range (V_{SV}) and the lighting condition (daylight, lower beams or upper beams). The

[126] *https://www.regulations.gov/document/NHTSA-2021-0002-0002.*

[127] The FCW and brake application need not be sequential.

[128] Overlap describes the location of the point on the front of the subject vehicle that would contact a pedestrian if no braking occurred. It refers to the percentage of the subject vehicle's overall width that the pedestrian test mannequin traverses. It is measured from the right or the left (depending on which side of the subject vehicle the pedestrian test mannequin originates).

subject vehicle's travel path in each of the test scenarios is straight.

1. Scenarios

Request To Add Scenarios

Many commenters suggested additional scenarios in PAEB testing.[129] Commenters urged NHTSA to include test devices representative of bicyclists and other vulnerable road users (VRUs), such as motorcyclists. A number of commenters recommended expanding additional scenarios involving pedestrians, such as older adult pedestrians who may walk slower than 3 mph, persons with disabilities, a running adult from the left scenario with dark lower beam or upper beam, pedestrians crossing from both directions, or pedestrians traveling against traffic.

NHTSA is highly interested in having PAEB address more scenarios, road users, and pedestrians than the scenarios covered by this final rule. NHTSA explained in the NPRM that the agency is actively conducting research to characterize, among other matters, the performance of AEB systems in response to bicycles and motorcycles, in both daylight and darkness conditions. However, the state of knowledge is not at the point where NHTSA can proceed with including bicycle and motorcycle surrogates in the new standard at this time. To illustrate, preliminary testing discussed in the NPRM identified issues with the design of the bicycle and motorcycle surrogates and their effect on the vehicles under test, indicating a need to learn more about these devices.[130] NHTSA is continuing its research to learn more, and present and future studies may well result in efforts to define test procedures, refine the bicycle and motorcycle surrogate devices, and characterize AEB system performance for possible incorporation into the FMVSS.

NHTSA proceeded with this rulemaking because it has the information needed to support an NPRM and final rule on the pedestrian behaviors addressed by the rule. Less is known about additional pedestrian behaviors to which commenters refer. NHTSA does not have the research necessary to determine well-reasoned and practicable performance requirements for the full range of travel behaviors pedestrians employ. Because developing the technical underpinnings and assessing the feasibility of potential further countermeasures need more time, NHTSA is adopting the PAEB test procedures proposed in the NPRM as a sound first step.

Request To Remove PAEB Scenarios

The Alliance requested that NHTSA not include the test of the stationary pedestrian test in nighttime conditions (S8.4). The Alliance stated that an analysis of real-world data from NHTSA's FARS database showed that fewer than 5 percent of stationary pedestrian crashes occur in dark, or low light, conditions, which is substantially lower than the other scenarios evaluated in the NPRM. The Alliance stated that the complexity in designing countermeasures is increased, particularly for vision-based systems, in discerning non-moving objects that may resemble the human form in low light conditions at high speed. The Alliance expressed concerns that this requirement would force the installation of additional sensors to verify the presence of an object in the roadway. The Alliance stated that this scenario has additional cost implications and underscores that meeting the requirements of the rule is not as straightforward as the agency suggested.

Similarly, MEMA questioned if crash data support the stationary pedestrian test, because the commenter believed it is unlikely a pedestrian would be completely stationary and without movement in any real-world condition. MEMA further stated that this test increases the probability of false activation from other stationary roadside objects. MEMA suggested that the moving along path scenario addresses real-world scenarios.

In response, NHTSA declines this request to eliminate the stationary pedestrian in nighttime conditions test. The commenters addressed the size and existence of the safety problem, with the Alliance providing an analysis showing that the standing pedestrian scenario comprises 5 percent (479 lives) of unlit nighttime crashes between 2014 and 2021. The unlit nighttime testing is designed to test a worst-case scenario, where there is no appreciable light other than that generated by the vehicle to aid in the detection of a pedestrian.[131] While the stationary position of the pedestrian test mannequin adds to the challenge of the test, real pedestrians encounter these potential dual dangers of darkness and stillness every day in the real world. NHTSA testing, discussed in the NPRM, has shown that AEB performance is reduced when testing the stationary scenario as compared to the along path scenario. Given the certainty that there are pedestrians outside in the dark each day, the likelihood that they may be stationary at times and not always in motion when a vehicle approaches, and the certainty of their vulnerable status vis-à-vis the vehicle (even low-speed vehicle impacts with pedestrians can result in fatalities and serious injuries), NHTSA believes that eliminating the test would not be reasonable. This is particularly so given that meeting the requirement is practicable.[132] Further, even if the agency accepts the Alliance analysis and interprets in a similar manner ''standing'' as equivalent to stationary during PAEB testing, NHTSA believes that the almost 50 annual fatalities over 8 years of data lends support for adopting the proposed test.

Ford believed that some tests are redundant and requested their removal. Ford recommends the removal of daytime 50 percent overlap crossing use cases as this will be 25 percent redundant with crossing use cases, as well as removing either the in-path stationary or moving scenarios which, the commenter believed, are redundant to each other.

In response, NHTSA does not agree the tests are redundant. Testing with a 25 percent overlap is more stringent than the 50 percent overlap test, as the pedestrian is exposed to the vehicle for a shorter amount of time. However, the 50 percent overlap test assesses a different scenario than the 25 percent overlap test. In the 50 percent overlap test, the vehicle comes upon the pedestrian later in the event. NHTSA is retaining the 50 percent overlap test, and the other mentioned tests, to ensure that PAEB systems are tuned to detect pedestrians across a wide and reasonable range in the roadway.

Lack of Dynamic Brake Support (DBS) Testing in PAEB Scenarios

Unlike for lead vehicle AEB, NHTSA did not propose that the AEB system supplement the driver's brake input with a dynamic brake support system. This is because NHTSA believes that, due to the sudden succession of events in a potential collision between a

[129] These commenters included NTSB, Advocates, the League, AMA, APBP, NSC, Forensic Rock, Consumer Reports, CAS, Radian Labs, AARP, NSC, America Walks, APBP, AARP, United spinal, Radian Labs, Adasky, VRUSC, AFB, Humanetics, and PVA.

[130] This report is expected to be completed within 2024.

[131] NHTSA expects that this performance will also be representative of, and beneficial to, nighttime conditions where brighter ambient light conditions exist.

[132] NHTSA's 2023 testing demonstrated that six out of six vehicles were able to fully meet the stationary requirements in both daylight and upper beam nighttime scenarios. The testing showed that half of the vehicles tested also were able to fully meet the proposed requirements for the lower beam nighttime scenario.

vehicle and a pedestrian, particularly for the pedestrian crossing path scenarios, a driver is unlikely to have enough time to react to the crash imminent event, and the vehicle will brake automatically without driver input. Further, NHTSA stated that it anticipates that AEB system designs would include DBS.

Advocates commented that NHTSA should either state that manual braking alone is insufficient to interrupt the AEB functionality or include testing of DBS functionality in the PAEB scenarios. AARP commented that it is important that the PAEB system function regardless of the characteristics of the vehicle's driver, and testing should reflect predictable variations such as those that result from the characteristics of older drivers.

In response, NHTSA is declining to add a manual braking test for pedestrians in this final rule. As stated in the NPRM, NHTSA expects that manufacturers will include this functionality when approaching a pedestrian. While the agency does not test PAEB with manual brake application, it does not make any distinction as to when AEB is required based on manual brake application. Thus, an AEB system tested for manual brake application under lead vehicle AEB testing will function in the same manner when approaching a pedestrian.

The agency also decided to test PAEB only without manual brake application due to the timing of crashes involving pedestrians, as it is not realistic to expect a quick enough response from a driver when presented with a warning to mitigate a collision under the proposed testing scenarios. NHTSA testing for lead vehicle AEB is premised on data that often an engaged driver does not brake enough to avoid a collision when presented with an FCW. However, the timing of a crossing path pedestrian scenario in some cases does not afford the ability to warn a driver and wait for a driver response. This difference between the lead vehicle and pedestrian crash scenarios renders requiring a manual brake application inappropriate for PAEB.[133] As such, the agency is declining to add a manual braking test for pedestrians at this time.

Lack of 25 Percent Overlap for PAEB Scenarios in Dark Conditions

Several comments suggested including PAEB performance tests with 25 percent overlap in dark conditions. Advocates requested that testing requirements at 25 percent overlap be included in the proposal, as a quarter of the vehicles tested by NHTSA in a limited study included such capability. Luminar stated the proposed PAEB testing overlap is arbitrary since the NPRM proposes PAEB testing at 25 percent overlap, but only 50 percent overlap for other scenarios, including some nighttime tests.

In response, as discussed in the NPRM, NHTSA declined to add the 25 percent overlap scenario for nighttime pedestrian AEB because it is not practicable at speeds relevant to the safety problem. The final rule has more benefits when pedestrian avoidance is tested at a more stringent and higher speed 50 percent overlap scenario.

NHTSA disagrees with Luminar that the overlap scenarios are arbitrary. UNECE Regulation No. 152 specifies the pedestrian target's positioning at the same location as a 50 percent overlap scenario. Euro NCAP also uses impact locations of 25, 50, and 75 percent. NHTSA still views testing at high speeds with a 25 percent overlap during nighttime scenarios as not practicable. The agency views setting higher speed tests for crossing path with a 50 percent overlap at night as merited and more appropriate for this final rule than specifying lower max speeds for a 25 percent overlap at night. Accordingly, NHTSA is declining to add a scenario for a high-speed test with a 25 percent overlap during nighttime condition.

Lack of Turning Scenarios

Several commenters recommended the inclusion of turning scenarios as part of the PAEB test requirements, *i.e.,* expanding the testing conditions to evaluate pedestrian during right and left turns of the subject vehicle.[134] Luminar stated that turning real word traffic conditions that mimic common pedestrian encounters in which the subject's movement partially or momentarily obscured and performance of crash avoidance technology in these scenarios is achievable. Some commenters stated that turning car-to-pedestrian AEB testing is performed as part of Euro NCAP.

In response, this final rule adopts the tests as proposed based on the research and other data demonstrating the efficacy and practicability of systems meeting the crossing path, stationary and along path scenarios. The data and technologies for test scenarios representing other crashes have not been analyzed as to their merit for inclusion in a possible FMVSS (as discussed throughout this document, rear-end crashes have been analyzed).

NHTSA included pedestrian AEB in turning from the left and turning from the right as a potential regulatory alternative for a more stringent rule. While commenters pointed out that Euro NCAP and other world NCAP programs offer some turning scenarios, NHTSA does not have sufficient information to propose or finalize incorporating a turning scenario at this time. NHTSA is not selecting this alternative in this final rule, however, and will consider conducting additional research and adopting requirements for turns in a future rulemaking, as appropriate. As discussed in the NPRM, NHTSA focused on the practicable scenarios that have the largest impact on the safety problem. While turning scenarios are responsible for around 48 percent of the total crash population for pedestrians, NHTSA crash data shows that 90 percent of fatal pedestrian-vehicle crashes, and 52 percent of the total pedestrian-vehicle crash population are covered under the standard NHTSA has developed.[135] In contrast, NHTSA data found that the turning right and turning left scenarios were found to only account for 1 percent and 4 percent of pedestrian fatalities, respectively.

[133] NHTSA is also mindful that implementing similar manual braking test scenarios for PAEB as for lead vehicle AEB may increase the likelihood of false positives when the systems are driven on the road. At 60 km/h (37.3 mph) automatic braking would need to occur at a minimum distance to the pedestrian of 20.25 meters with a 0.7g stop, which is a TTC of 1.21 sec, and it takes the vehicle 2.4 sec to stop. A pedestrian traveling with a walking speed of 5 km/h (3.1 mph) would cover 3.36 meters in this time, which puts that pedestrian 3.8 meters from the center of an average vehicle in the 25 percent overlap scenario, or about 2.9 meters from the side of the vehicle. In an urban setting, this would place the pedestrian in the buffer zone between the sidewalk and the travel lane, indicating the intent to cross the street. In this scenario the pedestrian would be a further 1.38 meters away in case of a warning issued 1 second prior to the minimum TTC described above, or more with a longer warning. This would place a pedestrian outside the buffer zone and solidly on the sidewalk. Adding additional time for a forward collision warning and driver reaction time increases the likelihood of false alerts, as it becomes increase difficult to determine the pedestrian's intent the further outside the travel lane the pedestrian is. Because of this, NHTSA proposed requiring, ''The vehicle must automatically apply the brakes and alert the vehicle operator such that the subject vehicle does not collide with the pedestrian test mannequin when tested using the procedures in S8 under the conditions specified in S6.''

[134] These commenters included Forest Rock, Luminar, APBP, NSC, the Coalition, Consumer Reports, and AARP.

[135] Mikio Yanagisawa, Elizabeth D. Swanson, Philip Azeredo, and Wassim Najm (2017, April) Estimation of potential safety benefits for pedestrian crash avoidance/mitigation systems (Report No. DOT HS 812 400) Washington, DC: National Highway Traffic Safety Administration, p xiii.

2. Subject Vehicle Speed Ranges

Increase PAEB Testing Speeds

Comments

NHTSA received many comments requesting the agency to increase the test speed of the vehicle.[136] Commenters generally stated that since the most common speed limit for a road where a pedestrian is killed is 45 mph, PAEB testing speeds should be increased above the proposed speeds (they generally did not suggest a maximum testing speed).

Agency Response

In response, as explained in the earlier section for lead vehicle testing speeds, NHTSA has bounded the testing speeds after considering practicability and other issues. These practicability concerns include, among others, the performance that can reasonably be achieved in the lead time provided for the final rule, the safety need that can be addressed, the safety of the testing personnel, and the practicalities of conducting a test that can be run repeatably and consistently without damaging lab equipment, to preserve the integrity and validity of the test data. NHTSA proposed and is adopting the highest practicable testing speeds. Accordingly, NHTSA has decided not to increase the test speeds for PAEB in this final rule. NHTSA considered, and is currently researching, other testing scenarios for PAEB, so more will be known about the future about the practicability and reasonableness of higher test speeds.

Reduce PAEB Testing Speeds

Comments

NHTSA received many comments from manufacturers and others requesting the agency to decrease the test speed of the vehicle.[137] Some manufacturers commented that NHTSA should permit low impact speeds when testing PAEB above certain testing speeds (when testing 30 km/h (19 mph) and above).

Like their comments on the lead vehicle speed tests, the Alliance and others suggested a hybrid approach that would permit some level of contact with the pedestrian test device for speeds above, *e.g.,* 30 km/h (19 mph). These commenters stated that providing full crash avoidance at higher speeds may not always be practicable due to increased potential for false positives under real world conditions. Additionally, the Alliance stated that the PAEB system must have sufficient information upon which to base its decision to apply braking force. The high testing speeds and no-contact requirement may force the AEB system to be too aggressive particularly in view of what can be unpredictable movement of pedestrians in and around the roadway environment. Honda suggested when PAEB is tested between 50 km/h and 65 km/h (31 mph to 40 mph), NHTSA should allow low speed contact up to 15 km/h (9.3 mph). Honda stated that the basis for the suggested speed threshold is that according to pedestrian injury data in the U.S., the risk of severe injury or fatality in pedestrian crashes below 15 km/h is highly unlikely.

The Alliance expressed concern about false positives or bad actors seeking to manipulate the AEB system into activating by imitating the act of entering the roadway environment. Mitsubishi was concerned about pedestrians who are about to jaywalk but stop due to approaching cars. The commenter stated that this behavior may lead to unnecessary activation and induce unintended consequences as current technology cannot predict pedestrian behavior with 100% accuracy. The Alliance and others stated that impact speeds of 25 km/h (16 mph) should be allowed as such impact speeds would have a reasonable safety outcome when the crash speed was mitigated from a higher speed testing. Some commenters stated that NHTSA should harmonize with UNECE Regulation No. 152, where impact speeds up to 40 km/h (25 mph) are allowed.

Agency Response

NHTSA is adopting the proposed testing speed ranges with a no-contact requirement and is not permitting repeat trials.

The commenters' main arguments in support of reducing the PAEB testing speeds are the potential increase in the likelihood of false positives due to difficulties in detecting pedestrians and classifying pedestrian action (such as intention to enter the roadway). In general, the commenters suggested allowing some level of pedestrian contact at above certain reduced speeds, ranging from 30 km/h to 50 km/h (10 mph to 31 mph), with most commenters suggesting around 40 km/h (25 mph) as the maximum speed for a no-contact requirement.

NHTSA proposed testing requirements that can be met, and that can avoid as many crashes, and mitigate as much harm, as practicable. For PAEB, NHTSA seeks to avoid crashes at the highest practicable speeds because of the vulnerability of a pedestrian in a vehicle crash. Vehicle contact with a pedestrian can be fatal or result in serious injury with potential long-term effects. NHTSA scrutinizes hybrid approaches, such as that of the Alliance, that incorporate as part of its framework the vehicle's hitting a pedestrian because the risk of injury to a pedestrian in a vehicle crash is so great. After reviewing the comments and other information, NHTSA does not believe that striking a pedestrian is an acceptable safety outcome given the availability of technologies that can prevent any kind of contact in the test scenarios.

Using the speed limit as a proxy for traveling speed, the data presented in the previous section of this document show that about 50 percent of pedestrian fatalities, and about 57 percent of injuries, occur on roads with a speed limit of 65 km/h (40 mph) or less. NHTSA believes an upper speed limit less than 65 km/h (40 mph) for a no-contact PAEB requirement would not be appropriate when test data on the performance of current vehicles show the practicability of meeting the proposed limits, particularly when more lead time is provided for the technology to evolve.

The injury curves and thresholds provided by some of the commenters show that below 25 km/h, there is a reduced probability of AIS3+ and MAIS3+ injury compared to impacts at greater speeds. However, the safety problem that PAEB can mitigate exists mainly at speeds above 40 km/h. Given that AEB, when developed to meet a no-contact requirement, could help mitigate the occurrence of pedestrian impacts up to 65 km/h (40 mph), NHTSA believes it unreasonable to set the no-contact limit at speeds at just a 40 km/h (25 mph) threshold.

As demonstrated by NHTSA testing, the technology has already proven effective at avoiding collisions at speeds up to 65 km/h (40 mph). As detailed in the research section, NHTSA found that a vehicle (the 2023 Toyota Corolla Hybrid) was able to avoid collision under all testing conditions up to the maximum proposed testing speeds requirement for all PAEB testing scenarios and speeds.[138] In addition,

[136] These commenters included the cities of Philadelphia, Nashville and Houston, the Richmond Ambulance Authority, Drive Smart Virginia, Teledyne, the Lidar Coalition, Luminar, Consumer Reports, Forensic Rock, Luminar, COMPAL, and NACTO.

[137] These commenters included the Alliance, Honda, Mobileye, Mitsubishi, Porsche, Volkswagen, Nissan, Toyota, and Aptiv.

[138] NHTSA's 2023 Light Vehicle Pedestrian Automatic Emergency Braking Research Test

four of the six vehicles tested achieved collision avoidance up to the proposed maximum speeds in almost all scenarios–some even in the most challenging dark lower beam scenarios. Additionally, another vehicle was able to achieve collision avoidance at all tested speeds in 3 scenarios.

NHTSA believes that the practicability of meeting the PAEB requirements of this final rule is demonstrated by the test data showing the performance of the 2023 Toyota Corolla Hybrid that passed all scenarios, and that of the several other vehicles that almost passed all scenarios. These test results are even more noteworthy because the tested vehicles did not have AEB systems designed to meet the requirements of proposed FMVSS No. 127. They were not prototypes or vehicles specially engineered to the specifications of the proposed standard for research purposes. To be clear, these were production vehicles already in the marketplace. The fact that current vehicles not particularly engineered to meet the new standard's requirements could meet them as designed, or with slight modification, further demonstrates the practicability of this final rule. Because current AEB systems are already capable of meeting the AEB requirements, NHTSA's assumption is confirmed that manufacturers will be able to meet the requirements of FMVSS No. 127 with the lead time provided, without major upgrades while mitigating excessive false positives or other unintended consequences.

Several commenters also believed that repeated trials should be allowed during PAEB testing. In response, NHTSA notes that the agency does not usually incorporate repeated trials in its vehicle compliance program. NHTSA's position has been to conduct a compliance test and, if an apparent noncompliance results, the agency should pursue the matter with the vehicle manufacturer without having to run a repeated trial. NHTSA's view is that the vehicle manufacturer is responsible for certifying the compliance of its vehicles and for ensuring the basis of its certification is sufficiently robust such that each vehicle will pass the test when tested by NHTSA. The agency acknowledges that for many years, NCAP testing (and other testing around the world) has encompassed repeated test trials to populate information about AEB in the consumer information program. NHTSA took the repeated trial approach in NCAP only because it was for a technology that was new or being developed. For more mature systems with a substantial record of real-world use, a single test run is preferable. A single test approach provides the agency the confidence that the performance it is regulating will perform as consistently as possible in the real world.

Regarding the comments received relating to AEB perception,[139] pedestrian detection, and classification, the MY 2023 vehicles tested for PAEB were generally able to avoid collision in all scenarios and at the majority of higher testing speeds. These vehicles are in production and on the road, demonstrating that solutions have been engineered to the PAEB perception in the real world. The engineering solutions have also accounted for no-contact testing performance. Also, Euro NCAP, while not a regulation, employs similar testing at similar speeds as the requirements in this final rule and many vehicles achieve a full score on Euro NCAP testing due to their collision avoidance capabilities. This performance further reinforces NHTSA's assessment that meeting the testing speeds of this final rule are practicable.

Evasive Steering (PAEB)

Comments

For the small overlap (25% test conditions), Porsche stated the last point to steer is much closer to the pedestrian than the last point to brake and the proposed test speeds may increase the likelihood for emergency braking engagement that may often be perceived by the customer as a false activation in scenarios where the driver is aware of the pedestrian on the road and planning to steer around them. Porsche stated that this dilemma is similar to high speed AEB for lead vehicles, but occurs at lower speeds, as small overlap pedestrian scenarios are harder to detect and predict.

Agency Response

In response, after considering the comments, and similar to its assessment of comments regarding lead vehicle evasive steering, the agency is not persuaded that evasive steering is an acceptable avoidance maneuver during testing. As thoroughly discussed previously, such factors as vehicle dynamics, traffic conditions and traffic participants all influence the safety benefit of a steering avoidance maneuver. A steering maneuver, as an avoidance maneuver, may not be as safe as a brake-in-lane maneuver, particularly in an urban environment. In any event, like for the lead vehicle situation, a manufacturer, outside of the testing requirements, may elect to detune or disengage the AEB system based on an emergency steering maneuver as long as the vehicle meets all the AEB requirements.

3. Pedestrian Test Device Speed

Comments

AARP and ASC commented on the proposed pedestrian test device speeds. AARP suggested that NHTSA consider whether testing the adult pedestrian scenarios at a walking speed of 3.1 mph (5 km/h) is sufficient to improve safety for those who walk at slower speeds. ASC stated that IIHS, and UNECE Regulation No. 152 and No. 131, require a speed of less than or equal to 5 km/h, which is representative of a walking adult pedestrian.

Agency Response

In response, NHTSA believes that the proposed crossing path test speed of 5 km/h (3.1 mph) for walking adult scenarios reasonably addresses the safety of adult pedestrians, including those who walk at slower speeds. Higher pedestrian test device walking speeds are more challenging for AEB systems. The longer a pedestrian is in the roadway, the more time a vehicle has to identify, classify, and avoid striking the pedestrian. NHTSA proposed that tests be performed at 5 km/h (3.1 mph) and 8 km/h (5 mph), as these speeds are representative of able-bodied adults walking and running. The agency expects that manufacturers will not turn pedestrian avoidance off at pedestrian speeds below those tested but will instead design systems that detect pedestrians moving at speeds lower than 5 km/h (3.1 mph) and avoid them. Further, the agency also included in the requirements testing with stationary pedestrian test devices, so that PAEB performs under three distinct pedestrian test mannequin speed scenarios (0 km/h, 5 km/h and 8 km/h). Therefore, NHTSA declines to include additional tests with pedestrian surrogate speeds lower than 5 km/h (3.1 mph) based on the absence of a safety need to do so.

In response to ASC, NHTSA notes that the 8 km/h (5 mph) test speed is used in the pedestrian crossing from the left scenario. It is representative of an able-bodied pedestrian running. This

Summary, available in the docket for this final rule (NHTSA–2023–0021).

[139] The performance of each AEB system depends on the ability of the system to use sensor data to appropriately detect and classify forward objects. The AEB system uses this detection and classification to decide if a collision is imminent and then avoid or mitigate the potential crash. Manufacturers and suppliers of AEB systems have worked to address unnecessary AEB activations through techniques such as sensor fusion, which combines and filters information from multiple sensors, and advanced predictive models.

performance test was proposed in the NPRM to ensure that pedestrian avoidance occurs in as wide a range of scenarios as is practicable. Data from NHTSA's testing of six model year 2023 vehicles showed that four of the six vehicles were able to meet the performance levels proposed in the NPRM. Based on the above, NHTSA concludes this test scenario is practical and appropriate for inclusion in the final rule. The agency also expects that if manufacturers can meet this performance for pedestrians crossing from the left at 8 km/h (5 mph), they can also avoid slower moving pedestrians, because in general the slower moving scenario poses a less demanding performance condition.

After considering the comments, the final rule adopts the 5 km/h (3 mph) speed for walking adult scenarios and the 8 km/h (5 mph) speed for running adult scenarios in crossing path PAEB tests, as proposed in the NPRM.

4. Overlap

Bosch commented on NHTSA's use of the term ''overlap'' in the NPRM. Overlap is a term used to describe the location of the point on the front of the subject vehicle that would make contact with a pedestrian if no braking occurred. The NPRM defined overlap as the percentage of the subject vehicle's overall width that the pedestrian test mannequin traverses. It is measured from the right or the left, depending on the side of the subject vehicle where the pedestrian test mannequin originates.

NHTSA proposed to use two overlaps for testing: a 25 percent overlap and a 50 percent overlap. The agency proposed the minimum overlap of 25 percent to allow for the test mannequin to fully be in the path of the subject vehicle. The agency also explained that the overlap determines the available time for the AEB system to detect and react when a collision with the test mannequin is imminent—a 50 percent overlap allows for more time than a 25 percent overlap. As for tolerances, the NPRM proposed that for each test run, the actual overlap would have to be within 0.15 m of the specified overlap.

Bosch did not object to the meaning of the term, the values proposed, or the tolerance provided for overlap, but suggested that NHTSA consider using the phrase ''percentage of the vehicle's width,'' rather than ''overlap.'' The commenter believed that the phrase accurately describes the lateral distance between the person in front of the vehicle and is terminology used by Euro NCAP. Bosch further stated that a similar approach by NHTSA would promote consistency and comparability in AEB performance evaluation across the industry.

In response, NHTSA declines to change the term ''overlap.'' The agency believes that the term overlap used in the proposal, and ''percent vehicle width'' used in Euro NCAP, are synonymous and not in conflict. Furthermore, the use of ''overlap'' is consistent with NHTSA's use of terms in its crashworthiness regulations, NHTSA's NCAP program, and NHTSA's practices in previous PAEB research. In addition, the definition of ''overlap'' in S8.1.2—the percentage of the subject vehicle's overall width—already includes the phrase put forth by Bosch.

5. Light Conditions

This final rule adopts the proposed requirements in the NPRM to specify compliance testing of AEB systems in daylight and dark conditions. The conditions ensure performance in a wide range of ambient light conditions. For daylight testing, the ambient illumination at the test site is not less than 2,000 lux. This minimum level approximates a typical roadway light level on an overcast day. The acceptable range also includes any higher illumination level including levels associated with bright sunlight on a clear day. For PAEB testing in darkness, the ambient illumination at the test site must be no greater than 0.2 lux. This value approximates roadway lighting in dark conditions without direct overhead lighting with moonlight and low levels of indirect light from other sources, such as reflected light from buildings and signage.

Comments

NHTSA received many comments to the proposed light conditions. Consumer advocacy groups and others generally support the proposed PAEB tests in daylight and darkness (with lower and upper beam) conditions.[140] NSC and GHSA emphasize that 75 to 77 percent of pedestrian fatalities occur in darkness or after dark, regardless of whether artificial lighting was present. GHSA also states that disadvantaged communities are overrepresented in pedestrian fatalities. Consumer Reports is supportive of PAEB in dark conditions based on the overrepresentation of nighttime pedestrian crashes among the total.

With respect to the use of headlamps during PAEB testing, Consumer Reports believes there does not appear to be a significant advantage of testing with the upper beams if the system already meets the requirements with the lower beams, and, that there is no guarantee that drivers will use the upper beams. In addition, Consumer Reports anticipates an increasing number of vehicles will be offered with adaptive driving beam (ABD) technology that can be used rather than lower beam and upper beams, and suggests that NHTSA's AEB tests test with ADB. Therefore, Consumer Reports suggests NHTSA replace the lower and upper beam language with language referring to the ''lowest level of active illumination,'' or similar, and require that the system pass the test at this level of lighting. Some equipment manufacturers expressed support for the proposed PAEB tests in daylight and darkness conditions, stating that infra-red sensors would increase safety for dark lighting conditions.

The Lidar Coalition expressed strong support for the proposed testing of PAEB in low light conditions with no overhead lighting and only lower beams activated. The commenter states that NHTSA is correctly focusing on addressing the largest portion of pedestrian fatalities on U.S. roadways. The Lidar Coalition suggests that NHTSA prioritize testing in the darkest realistic conditions possible. The commenter states that the proposed test procedure in dark conditions will evaluate PAEB technologies in the real-world scenarios where the commenter believes these systems are most needed, when the human eye falls short. The Lidar Coalition states the Insurance Institute for Highway Safety found that in darkness conditions, camera and radar based PAEB systems fail in every instance to detect pedestrians. They additionally referenced the GHSA finding that in an evaluation of roadway fatalities in 2020, 75% of pedestrian fatalities occur at night.

COMPAL supports a finding of a safety need for PAEB under dark condition and higher speeds (greater than 60 km/h (37.5 mph)), and believes that placing infrared sensors as a forward-looking sensor in PAEB testing can improve AEB functionality in challenging situations, such as testing for the crossing child obstructed scenario and the crossing adult running from the left. It states that infrared sensors should not be considered an emerging technology and that they work well in sun glare and darkness conditions and can detect a pedestrian much further than typical headlamps.

Vehicle manufacturers and equipment manufacturers generally oppose the proposed PAEB dark test conditions with only low beams because of the

[140] These commenters included NSC, NTSB, GHSA, Consumer Reports, Forensic Rock, the Lidar Coalition, ZF, and COMPAL.

limited ability to illuminate pedestrians. The Alliance, Ford, Nissan, Toyota, Honda, MEMA, Mobileye and Adasky support the idea of allowing the use of the advanced lighting technology (such as ADB headlamps) if available on the model as standard equipment, or to incorporate the use of streetlights to simulate urban traffic conditions. The Alliance argues that allowing all dark lighting conditions to be tested with the advanced lighting features activated aligns with NHTSA's considerations for similar testing in the proposed NCAP upgrade and further promotes the adoption of these advanced lighting systems. Porsche states that the required nighttime PAEB performance requirements at the higher relative speeds is likely to exceed the technical capabilities of many current AEB system hardware. MEMA states that, in dark environments without streetlights, the lower beams would not be active because upper beams provide a better view, so this lower beam test is not depicting a real driving situation.

Ford and Nissan also state that the lighting requirements in FMVSS No. 108 impact feasibility and practicability in testing certain low light PAEB tests. Similarly, Honda commented that the primary sensor for detecting pedestrian targets is the camera, which relies on optical information. Honda state this exceeds the recognition capability and reliability range of current camera systems and will lead to excessive false activations.

Agency Response

After considering the comments, NHTSA has determined there is a safety need for the dark testing requirement, given the number of nighttime pedestrian fatalities and IIHS's finding that several AEB systems that performed well in daylight performed poorly in dark conditions. The agency has adopted the dark lighting requirements as proposed. However, as explained in the discussion below, NHTSA concurs that more time is needed to meet the dark lighting conditions. This final rule provides five years of lead time to do the additional engineering work needed to bring poorer performing AEB systems to a level where they can meet this final rule's requirements.

Consumer Reports commented that testing with upper beam may be redundant if the system already meets the requirements with the lower beam. While this might be true for some systems, agency testing performed for the NPRM showed inconsistent performance while testing with the upper beam.[141] In rare cases, vehicles performed better with lower beams illuminated than with upper beam. NHTSA is adopting an upper beam test to assure the functionality of the AEB system when the driver uses the upper beam.

Forensic Rock, Lidar Coalition, COMPAL and ZF, appear to assert that all scenarios should be tested under dark and daylight condition, or that testing should be performed in the darkest realistic condition. NHTSA does not concur with that view, as the agency must consider, among other matters, the safety problem being addressed (to ensure the FMVSSs appropriately address a safety need), and the practicability and capabilities of the technology. NHTSA has assessed the tests and performance requirements adopted in this final rule to ensure each satisfies the requirements for FMVSS established in the Safety Act. Some tests did not pass NHTSA's assessment and were not proposed. To illustrate, the test results for the crossing scenarios at 25% overlap at night indicate meeting the test is impracticable at this time.[142] Similarly, the obstructed child scenario depicts a situation that very rarely occurs at night (as noted by ZF as well), so NHTSA did not propose testing for such a scenario at night as not practical or reasonable.[143]

Many commenters believe that testing should be allowed with the adaptive driving beam (ADB) active. NHTSA disagrees. NHTSA does not require ADB, whereas the lower beam and upper beam are required by the FMVSSs on the vehicle. Further, even if an ADB system were installed on the vehicle, a driver may not use it. NHTSA does not believe it appropriate to tie the life-saving benefits associated with AEB to a technology (ADB) that a driver may or may not use on a trip.

Additionally, ADB still employs the lower beam and upper beam, and merely switches automatically to the lower beam at times appropriate to do so. Thus, even if a driver has ADB operational, if the ADB reverts to a lower beam on a large portion of the beam area, in effect the operating conditions would be lower beam only, which, under the commenters' suggested approach, would not have been assessed with AEB. Testing PAEB with ADB on could, under the commenters' suggested testing conditions, essentially amount to the agency only testing the upper beam condition. Such an outcome would be undesirable from a safety standpoint, as most drivers rarely use their upper beams when operating vehicles at night. IIHS test data of 3,200 isolated vehicles (where other vehicles were at least 10 or more seconds away) showed that only 18 percent had their upper beams on.[144] At one unlit urban location, IIHS data showed that upper beam use was less than 1 percent. IIHS found that even on rural roads, drivers used their upper beams less than half of the time they should have for maximum safety, on average. Testing during daylight and dark with lower beam and upper beam provides confidence that in urban dark lighted environment, PAEB will perform even with only the lower beam operational.

NHTSA understands that lower beam testing scenarios may require better lowlight cameras and may require improved recognition algorithms for the lower performing AEB systems, which is why the agency is affording manufacturers additional time to engineer such systems up to FMVSS No. 127 performance. NHTSA's testing conducted for the NPRM indicated that the proposed PAEB dark scenarios represent ambitious, yet achievable performance criteria.[145] The latest agency research, detailed in this notice, on six model year 2023 vehicles found that in the scenario where the pedestrian is approaching from the right, five of the six vehicles tested were able to meet the performance requirements for the upper beam lighting condition, and four of the six were able to meet the lower beam lighting condition. In the scenario where the pedestrian is stationary, all vehicles were able to meet the upper beam light condition, and three of the six vehicles were able to meet the lower beam testing condition. The final nighttime scenario, with the pedestrian moving along the vehicle's path, four vehicles met the performance requirements for the upper beam condition, and a single vehicle met the lower beam condition. The 2023 Toyota Corolla was able to avoid collision in two instances and had impact speeds of about 5 km/h or less in the other three tests.

These data indicate the practicability of meeting the PAEB tests proposed in the NPRM. Although not all manufacturers can currently certify to

[141] *https://www.regulations.gov/docket/NHTSA-2023-0021/document* (last accessed 12/8/2023).

[142] *https://www.regulations.gov/docket/NHTSA-2023-0021/document.*

[143] *Id.*

[144] *https://www.iihs.org/news/detail/few-drivers-use-their-high-beams-study-finds* (last accessed 11/18/2023).

[145] *https://www.regulations.gov/docket/NHTSA-2023-0021/document* (last accessed 12/8/2023).

all dark tests, AEB technologies are evolving rapidly, with significant improvements occurring even in the last year or two of NHTSA's AEB research program. NHTSA is providing five years for further development and integration of the technology into the new vehicle fleet. The agency adopts the upper and lower beam conditions as proposed in the NPRM without change, except for providing more lead time to meet the standard's requirements.

As for Honda's concerns about the sensors that they use, *i.e.,* cameras, NHTSA is aware of different sensor combinations capable of detecting pedestrian mannequins, as is evidenced by the higher performing vehicles identified during NHTSA testing. While Honda's current generation cameras may have recognition capability and reliability range challenges, other sensors and sensor combinations do not. NHTSA is not required to limit performance requirements to what one particular manufacturer using specific sensors is capable of doing at a given point in time. If Honda faces the challenges it describes, then software and possibly hardware updates may be necessary for Honda to meet the require performance.

6. Testing Setup

Pedestrian, Obstructed Running Child, Crossing Path From the Right

In the test of an obstructed running child crossing from the right, an obstructed child pedestrian test device moves in the vehicle's travel path from the right of the travel path. The pedestrian surrogate crosses the subject vehicle's travel path from in front of two stopped vehicle test devices (VTDs). The VTDs are parked to the right of the subject vehicle's travel path, in the adjacent lane, at 1.0 m (3 ft) from the side of the subject vehicle. The VTDs are parked one after the other and are facing in the same direction as the subject vehicle. The subject vehicle must avoid collision with the child pedestrian surrogate without manual brake input.

Comments and Agency Responses

Porsche, Volkswagen, FCA, and ASC commented on the proposed obstructed pedestrian scenario in PAEB performance tests. Porsche and Volkswagen stated that the distance between the pedestrian test dummy and the farthest obstructing vehicle is not specified in the proposed regulation (*i.e.,* S8.3.3). The commenters believe this is critical to be defined because the level of obstruction of the child test dummy can only be defined by this distance. If multiple distances are required to reflect full and partial obstruction, then each specific test scenario should be defined.

In response, NHTSA agrees with the commenters that the proposed testing setup should have, but did not, include the distance between a pedestrian test mannequin and the obstructing vehicle device positioned further from a subject vehicle. In this final rule, NHTSA adopts the following regulatory text language to clarify the test setup for the obstructed pedestrian crossing scenario: ''[t]he frontmost plane of the vehicle test device furthermost from the subject vehicle is located 1.0 ± 0.1 m from the parallel contact plane (to the subject vehicle's frontmost plane) on the pedestrian test mannequin.''

ASC stated that the vehicles obstructing the mannequin should be specified. The commenter believes that due to the large size of common vehicles sold in the US (*e.g.,* pick-ups and sport utility vehicles), specific vehicle models or types should be defined for this test configuration.

In response, the agency disagrees with ASC that NHTSA should specify models or types of the obstructing vehicles. The regulatory text specifies that two vehicle test devices are used as an obstruction in obstructed pedestrian crossing tests and the text also provides the dimensional specifications and other measurements of the vehicle test device. Therefore, the standard includes sufficient information specifying the obstructing vehicles to ensure repeatable and reproducible testing.

FCA commented that the obstruction vehicles in the research testing were a Honda Accord and Toyota Highlander and every research test used this combination of real vehicles as obstructions, but that there was no data in the NPRM or the research about how these scenarios react or correlate to the vehicle test devices proposed for the FMVSS at S8.3.3(g). FCA expressed concern that this could lead to added practicability or other concerns for the associated test condition.

In response, NHTSA highlights the additional testing performed. In this course of this testing, NHTSA evaluated using real vehicles, the 4Active vehicle test device, and the ABD test device.[146] The agency found no appreciable differences in performance between real vehicles and either vehicle test device. Thus, NHTSA believes that using the vehicle test device in the obstructed child crossing scenario is practicable and reasonable.

With respect to Bosch's suggestion that the maximum allowed travel path deviation needs to be specified as ⅛th of the subject vehicle width and not the 0.3 m allowed in the proposal, the agency agrees in general that the tolerance for the expected point of contact should be from the subject vehicle and not the lane. Thus, in the proposal, the tolerance for the expected contact point was specified as the difference between the actual overlap and the specified overlap. This tolerance was specified and is finalized independent of the vehicle's position in the lane. The NPRM's proposed regulatory text stated: ''For each test run, the actual overlap will be within 0.15 m of the specified overlap.'' This is a tighter tolerance than Bosch suggested (⅛th of the average vehicle width is approx. 0.22 m). As such, the agency does not believe this will allow the situation Bosch proposed (where 25 percent overlap can be mistaken for a 50 percent overlap, and 50 percent overlap can be mistaken for 25 percent overlap from the left) to occur.

FCA suggested that NHTSA should consider using a standard road width and simply positioning the pedestrian mannequins across percentages of the lane, as this would be indicative of a position in the real world. FCA stated that NHTSA intended to position pedestrians according to ratios derived from the overall width of each vehicle, but that this set up can be overly complicated.

NHTSA disagrees with FCA that applying mannequin positions—described as percentages of the width of a standard test lane—would simplify test procedures. First, the agency is not aware of a standard test lane specification that is universally accepted for PAEB tests, and which can represent various types of roads in the real-world. Such roads would include lanes marked by two lines on highways, lanes marked by only one line in urban residential sections, and lanes without any marking in rural areas. Second, applying a same mannequin position within the test lane for all PAEB tests could cause unnecessary confusion because it might result in different overlap scenarios for different sizes of subject vehicles. For example, a pedestrian mannequin positioned at a certain percentage of the lane width may be appropriate for a 25 percent overlap test with a full-size pickup truck. However, such positioning may result in an invalid test with a small compact car—for example, a Fiat 500—since a mannequin at the same lateral

[146] ''NHTSA's 2023 Light Vehicle Automatic Emergency Braking Research Test Summary'' Available in the docket for this final rule (NHTSA–2023–0021).

position within the test lane may not make a contact with such a small subject vehicle. Therefore, NHTSA declines to adopt a mannequin position that is defined by lane width and not percent overlap.

J. Procedures for Testing False Activation

This section describes the false activation performance tests adopted by this final rule. These tests are sometimes referred to as ''false-positive'' tests. After considering the comments to the NPRM, NHTSA has adopted the proposed procedures tests with little change. This section responds to the comments and explains NHTSA's reasons for adopting the provisions set forth in this final rule. For the convenience of readers, a list of the test specifications can be found in appendix C to this final rule preamble.

This final rule adopts the two proposed false activation testing scenarios—the steel trench plate test and the vehicle pass-through scenario. Both tests are performed during daylight. Testing is performed with manual brake application and without manual brake application. The performance criterion is that the AEB system must not engage the brakes to create a peak deceleration of more than 0.25 g additional deceleration than any manual brake application would generate (if used).

Comments

NHTSA received comments both supporting and opposing the proposed false activation tests. Commenters in favor of including the tests in FMVSS No. 127 include: Consumer Reports, Advocates, the Lidar Coalition, AAA, Bosch, Porsche, and CAS. Consumer Reports states that it is important to limit false activations to maximize safety and consumer acceptance. AAA supported the steel trench plate test, stating that it is important to ensure that increased system sensitivity does not occur at the expense of unnecessary braking. CAS suggested the addition of a third test involving a railroad crossing. The Lidar Coalition stated that false positive tests are important for evaluating both sensing modalities and perception systems, as well as the interplay between both pieces of an effective AEB and PAEB system.

NHTSA also received comments opposing inclusion of one or both of the tests. Volkswagen recommended eliminating the proposed false activation tests from the rule, believing the tests have no comparable real-world relevance. Luminar expressed similar concern about real-world similarity.

Agency Response

After considering the comments, NHTSA has decided to maintain the false positive testing scenarios for AEB proposed in the NPRM. The proposed false activation tests establish only a baseline for system functionality and are by no means comprehensive, nor sufficient to eliminate susceptibility to false activations. However, the tests are a means to establish at least a minimum threshold of performance in the standard.

NHTSA expects that vehicle manufacturers will design AEB systems to thoroughly address the potential for false activations.[147] Previous implementations of other technologies have shown that manufacturers have a strong incentive to mitigate false positives. Vehicles that have excessive false positive activations may pose an unreasonable risk to safety and may be considered to have a safety-related defect. NHTSA understands from industry comments to this rulemaking and others that industry generally designs their systems to minimize false activations.[148]

Nonetheless, NHTSA is including the false activation tests in this final rule because NHTSA has seen evidence of false activations in those scenarios and because NHTSA expects that the scenario might be particularly challenging for AEB systems. Thus, the agency does not agree to remove or add additional test scenarios or conditions to the test scenarios at this time. NHTSA is including the tests in FMVSS No. 127 to establish a reasonable minimum when it comes to false activation assessment and mitigation; the agency may add to the tests in the future if the need arises.

CR commented that a 0.25g deceleration threshold is too high, stating that a ''0.25g braking event is noticeable by passengers and could confuse or distract the driver.'' In response, the requirement is for peak additional deceleration, not for average deceleration. In other words, the deceleration that Consumer Reports is describing would likely not meet the requirement. Consumer Reports is referring to a brief, not sustained, brake pulse, which would be noticeable. The 0.25g peak deceleration threshold was chosen as an obvious indication of external braking that is easily measurable by testing equipment.

Bosch supported the proposed steel trench plate properties for the steel trench plate test but suggested that the orientation of the plate be accurately aligned within a tolerance, *e.g.,* aligning the leading edge of the plate 90 degrees plus or minus 0.5 degrees to the centerline of the test vehicle.

In response, NHTSA does not agree with Bosch that a tolerance is appropriate for positioning of the steel plate, particularly such a low tolerance as 0.5 degrees. The steel plate false activation test is an established test which has been performed without a specific tolerance for the alignment of the steel plate for an extended period without any indication that the lack of a tolerance influences the outcome of the tests. Further, Bosch has not provided any data in support of their suggestion, and NHTSA does not have any data suggesting that any slight misalignment of the steel plate influences the results.

Porsche stated that they support the false positive tests with some suggested improvements. Porsche stated that they suggest modifying the pass-through test lateral distance gap in S9.3.1(b) to be in relation to the exterior of the vehicle body instead of the front wheels. Porsche also suggested adding a test matrix table to section S8.1. Volkswagen suggested that NHTSA better define the test scenarios, such as with regard to the exterior dimensions of the stationary vehicles in the pass-through gap test and whether there is a manual brake application in either test.

In response, while Porsche states that the gap between the vehicles should be measured based on the exterior of the vehicles, not the wheels, the commenter did not provide any data or reasoning for the suggestion. Volkswagen suggests that more detail should be given on the exterior dimensions of the stationary vehicles but also did not provide any supporting data or reasoning. NHTSA had evaluated these requirements when developing the NPRM and found them to be sufficient. Accordingly, the agency is not revising how the space between the vehicles is measured and how we specify the dimensions of the two stationary vehicles.

Porsche and Volkswagens both state it is unclear whether testing is to be done with and without manual brake application. In response, NHTSA notes

[147] 88 FR 38632 at 38696.

[148] In response to a 2022 NCAP Request for Comment, the Alliance stated in their comments to the 2022 NCAP notice where NHTSA requested comment on the inclusion of false positive tests in NCAP the Alliance stated that vehicle manufacturers will optimize their systems to minimize false positive activations for consumer acceptance purposes, and thus such tests will not be necessary. Similarly, in response to the same 2022 NCAP notice, Honda stated that vehicle manufacturers must already account for false positives when considering marketability and HMI. These comments are available in this docket *https://www.regulations.gov/document/NHTSA-2023-0020-0001.*

that in the NPRM, NHTSA specifically states that it would test vehicles with and without manual application. While the agency does not believe a table is needed specifying the key parameters when testing for lead vehicle and PAEB, NHTSA agrees that the proposed regulatory text was not clear on this topic. Thus, the agency has revised the regulatory text for the steel plate and for the pass-through test to be clear that testing is conducted with manual brake application and without manual brake application.

K. Track Testing Conditions

1. Environmental Test Conditions

Lighting Conditions

Under this final rule, NHTSA will test AEB systems in daylight for lead vehicle AEB and PAEB testing, as well as in darkness for PAEB testing. The light conditions ensure performance in a wide range of ambient light conditions. For all daylight testing, the ambient illumination at the test site is not less than 2,000 lux, which approximates the minimum light level on a typical roadway on an overcast day. To better ensure test repeatability, testing may not be performed while the intended travel path is such that the heading angle of the vehicle is less than 25 degrees with respect to the sun and while the solar elevation angle is less than 15 degrees. The intensity of low-angle sunlight can create sensor anomalies that may lead to unrepeatable test results.

For PAEB darkness testing, the ambient illumination at the test site must be no greater than 0.2 lux. This value approximates roadway lighting in dark conditions without direct overhead lighting with moonlight and low levels of indirect light from other sources. This darkness level accounts for the effect ambient light has on AEB performance, particularly for camera-based systems. It ensures robust performance of all AEB systems, regardless of what types of sensors are used.

Comments

NHTSA received several comments on the lighting conditions,[149] particularly the proposed ambient illumination requirement (*i.e.,* any level at or below 0.2 lux) for darkness PAEB testing.

HATCI and others believe that NHTSA should use nighttime lighting conditions for PAEB testing that are more characteristic of urban environments. HATCI states that NHTSA would use the same specification for lower and upper beams, 0.2 lux, but that an ambient environment of 0.2 lux is extremely dark and is unlikely to be representative of real-world conditions in an urban area. HATCI stated that since 82% of the pedestrian fatalities occur in urban areas, these environmental conditions should be reflected in the test procedures. HATCI suggests that the agency should include overhead lights as it is more representative of the urban environment. The commenters state that additional lighting, including streetlights, would align lighting conditions with Euro NCAP. In contrast, AAA believes NHTSA should refrain from allowing testing under artificially bright overhead lighting for PAEB system performance requirements in darkness conditions.

Agency Response

After considering the comments submitted about the lighting conditions, NHTSA has decided to adopt the proposed lighting conditions for several reasons. First, the agency is finalizing the proposed lighting conditions because they present the most challenging, but practicable, lighting conditions for PAEB systems. Because they will be able to meet the most challenging condition, PAEB will be able to perform well in situations with more light, like roads that have streetlights. Although NHTSA agrees with commenters that 0.2 lux may not be representative of urban scenarios at night, the agency disagrees with HATCI, MEMA, Bosch, and Mitsubishi that testing should be conducted with lighting conditions that mimic urban areas. Testing in dark conditions, below 0.2 lux, represents the worst lighting case, where pedestrians are most at risk.[150]

Second, testing during daylight and dark with lower beams and upper beams provides confidence that in urban dark lighted environments, PAEB will perform even if the agency does not test under such a condition

In addition, the agency conducted confirmatory testing that indicates that the proposed lighting conditions represented ambitious, yet achievable conditions. The agency conducted additional research on the performance of the AEB systems of six model year 2023 vehicles when approaching a pedestrian. The darkness testing occurred with less than 0.2 lux of ambient lighting. In the scenario where the pedestrian is approaching from the right, five of the six vehicles tested were able to meet the performance requirements for the upper beam lighting condition, and four of the six were able to meet the lower beam lighting condition. In the scenario where the pedestrian is stationary, all vehicles were able to meet the upper beam light condition, and three of the six vehicles were able to meet the lower beam testing condition. The final nighttime scenario, with the pedestrian moving along the vehicle's path, four vehicles met the performance requirements for the upper beam condition, and a single vehicle met the lower beam condition. NHTSA believes that this data show that testing with the ambient light below 0.2 lux is practicable. For the above reasons, NHTSA believes the lighting conditions adopted by this final rule best ensure that PAEB systems work in all environments where pedestrians are at the highest safety risk.

As for the proposed PAEB daylight testing conditions, several sensor suppliers suggested that the agency should reconsider the sunlight glare avoidance requirement (*i.e.,* not driving toward or away from the sun—less than 25 degrees in vertical and 15 degrees in horizontal directions). Adasky and the Lidar Coalition stated that the NHTSA should include additional real world environmental conditions, such as direct sunlight.

In response, the agency agrees with Luminar that there is a safety issue on the road when drivers operate in direct sunlight. However, the agency does not have enough test data to assess the statements from manufacturers of lidar systems (Adasky, Luminar, The Lidar Coalition) on the efficacy of LIDAR systems and potential sensor saturation by testing in direct sunlight. Additionally, NHTSA believes that, if research is warranted to assess the accuracy of the companies' assertions, that would delay this rulemaking. Thus, NHTSA declines to change the final rule as requested.

Ambient Temperature

This final rule adopts the proposed specification that the ambient temperature in the test area be between 0 Celsius (32 °F) and 40 Celsius (104 °F) during AEB testing. This ambient temperature range matches the range specified in NHTSA's safety standard for brake system performance and is representative of the wide range of conditions that AEB-equipped vehicles encounter. As explained in the NPRM,

[149] These commenters included HATCI, MEMA, Bosch, Mitsubishi, and AAA.

[150] For the proposed PAEB testing in darkness, the ambient illumination at the test site must be no greater than 0.2 lux. This value approximates roadway lighting in dark conditions without direct overhead lighting with moonlight and low levels of indirect light from other sources, such as reflected light from buildings and signage.

while AEB controls and sensors can operate at lower temperatures, the limiting factor here is the braking performance.

Comments

FCA commented that, given the only proposed outcome is ''no contact'' and passing results in the research data are often less than one meter, brake stopping performance and variation become crucial. FCA stated that because of this, testing at temperature becomes a primary concern. FCA suggested that if NHTSA believes braking performance at hot temperatures is the worst case, it should make that explanatory statement. However, if NHTSA believes braking is worst case at cold temperatures, it should assess AEB performance at the freezing point minimum temperature. Otherwise, it should limit the regulatory testing to a much more modest range to accommodate the existing data.

Agency Response

In response, NHTSA notes that FCA did not provide the testing range that it believes would be acceptable, or explain its concern about aspects of the proposed range. NHTSA believes that braking performance would be relatively unaffected by outside temperature because the procedures specify that there will be an initial braking temperature which ensures that the brakes are warm when tested, and has specified a burnishing procedure to ensure that the brakes perform consistently. The final rule specifies a testing range consistent with the ranges included in the existing braking standards applying to the vehicles subject to FMVSS No. 127. Those testing temperatures have worked well in those braking standards, and NHTSA is unaware of information indicating they would be unacceptable for this rule. Accordingly, NHTSA adopts the ambient temperature range proposed in the NPRM without change.

Wind Conditions

This final rule adopts the proposed specification that the maximum wind speed during AEB compliance testing be no greater than 10 m/s (22 mph) for lead vehicle avoidance tests and 6.7 m/s (15 mph) for pedestrian avoidance tests. Excessive wind during testing could disturb the test devices in various ways. For example, high wind speeds could affect the ability of the VTD to maintain consistent speed and/or lateral position, or could while cause the pedestrian mannequin to bend or sway unpredictably.

Comments

Bosch and Zoox are concerned with testing up to the proposed maximum wind speed. Bosch states that the testing equipment is not able to consistently maintain stability in windy conditions. Bosch and MEMA suggest using language similar to UNECE R152 which specifies testing only when there is no wind present that is liable to affect the results. Zoox suggests reducing the maximum test wind speed from 10 m/s to 5 m/s for all AEB testing.

Agency Response

NHTSA declines to adopt the suggested changes. The wind speeds included in the proposal and adopted in this final rule have long been used by the agency in AEB testing and testing of other systems in the FMVSS. As stated in the NPRM, these are the same maximum wind speeds specified for AEB tests in the agency's AEB NCAP test procedures and PAEB draft research test procedure without problems. The wind speed specified for lead vehicle avoidance tests is also in line with the maximum wind speed specified for passenger vehicles in FMVSS No. 126, ''Electronic stability control systems for light vehicles.'' The specification has been workable for many years.

Commenters did not explain the basis for characterizing the proposed wind speeds as windy conditions, or what winds could affect test results. They provided no information showing that the proposed wind speeds would affect braking performance and test equipment stability. NHTSA believes that the UNECE R152 approach would not be helpful, as it is open-ended about wind speeds. It would not provide manufacturers with notice of the wind speeds under which the agency would test. NHTSA believes its approach of specifying the specific range of wind speeds, as opposed to leaving it open ended and undefined like UNECE R152, provides notice about the test conditions under which compliance testing would be conducted and more assurance about what NHTSA considers a valid test. The agency therefore adopts the provisions for wind speed without change.

Precipitation

NHTSA adopts the proposed specification that NHTSA will not conduct AEB compliance tests during periods of precipitation, including rain, snow, sleet, or hail. The presence of precipitation could influence the outcome of the tests because wet, icy, or snow-covered pavement has lower friction. Conducting a test under those conditions also poses risks to lab personnel. Additionally, the presence of precipitation like rain, snow, sleet, or hail, makes it much more difficult to reproduce a friction level with good precision. That is, even if NHTSA were able to run a particular test on a pavement with precipitation, replicating the same test conditions may not be possible.

Comments

Consumer Reports stated that the variation of AEB performance in different conditions is why this additional testing is needed. It noted that in its experience evaluating vehicles' wet-road braking performance, it is feasible to establish objective test procedures for conditions in which the ground is wet.

Agency Response

In response, NHTSA does not have the information necessary to demonstrate that such testing would be possible for compliance testing. NHTSA is encouraged that Consumer Reports conducts wet pavement testing because such testing can add to the agency's knowledge in this area. NHTSA encourages Consumer Reports to share more detailed information about its wet-road braking to possibly provide a foundation for future NHTSA research.

Visibility

This final rule adopts the proposed specification that AEB performance tests will be conducted when visibility at the test site is unaffected by fog, smoke, ash, or airborne particulate matter. Reduced visibility in the presence of fog or other particulate matter is difficult to reproduce in a manner that produces repeatable test results. While NHTSA considered a minimum visibility range during the development of the proposal, the agency proposed a limitation on the presence of conditions that would obstruct visibility during AEB testing. NHTSA sought comment on whether to adopt a minimum visibility range.

Comments

ASC, ZF, and MEMA supported the proposed visibility conditions for AEB testing. ASC, MEMA and ZF stated that defining minimum visibility ranges would be challenging due to current sensor performance and creating repeatable test conditions.

Other commentators requested a minimum visibility requirement and gave suggestions on how to create a minimum visibility definition. The Alliance stated that this should be objectively defined. Mobileye suggests that a minimum level of visibility could

be defined as the visibility that allows a human driver to see the target within 5 seconds time to collision. Bosch and FCA states that NHTSA should establish a precise and comprehensive definition for ''visibility'' (*e.g.,* that visibility will be greater than 1 km, 0.5 km, etc.). Bosch and Volkswagen state that the test must ensure that the horizontal visibility range will allow the target to be clearly observed throughout the test. Aptiv and Consumer Reports recommend adding additional testing to account for real-world conditions such as sun glare, rain, fog and smoke.

Agency Response

NHTSA adopts the provisions proposed in the NPRM without change, for the reasons provided in the proposal. The agency agrees with commenters that there may be merits to having an objective way to measure visibility, but defining a minimum visibility range that is objective is challenging, as noted by ASC, ZF, and MEMA. Bosch suggested requiring visibility be measured as greater than ''X'' kilometers, similar to NCAP programs,[151] and Mobileye suggested an approach.

NHTSA will further consider the pros and cons of these and other approaches and determine whether to consider them in a future rulemaking. For now, it does not appear that the commenters' requested changes to the visibility metric proposed in the NPRM present a better measurement than the limitation on the presence of conditions that would obstruct visibility. Therefore, NHTSA will adopt the provisions described in the NPRM.

2. Road/Test Track Conditions

Surface

This final rule adopts the proposed specification that NHTSA will test on a dry, uniform, solid-paved surface with a peak friction coefficient (PFC) of 1.02 when measured using an ASTM F2493 standard reference test tire, in accordance with ASTM E1337–19 at a speed of 64.4 km/h (40 mph), without water delivery.[152] Surface friction is a critical factor in testing systems that rely heavily on brake system performance testing, such as AEB. The presence of moisture will significantly change the measured performance of a braking system. A dry surface is more consistent and provides for greater test repeatability.

Comments

MEMA supports the test track surface having a peak friction coefficient of 1.02. AAA recommended, based on previous testing, that there should be some tolerance allowed in terms of peak friction coefficient to allow for a greater number of closed-course facilities to be suitable for confirmation testing. FCA asked for clarification, as they see a maximum Roadway Friction Coefficient (RFC) but no mention of any minimum RFC. In addition, FCA suggested adopting a similar calculation for over speed/under speed tests within FMVSS No. 127 as in FMVSS No. 135. The Alliance commented that NHTSA should define the tolerance for the required test track surface with maximum and minimum friction coefficients. It stated that such a tolerance would ensure fairness when conducting tests across different test facilities, reduce the cost/burden associated with maintaining a test surface having a specific PFC, particularly since this value can change over time, and is consistent with NCAP's Crash Avoidance test procedures.

Agency Response

NHTSA first addressed this issue in the final rule upgrading the motorcycle brake system standard published in 2012.[153] NHTSA stated that, by specifying a single PFC, the intent is not to specify testing only on surfaces with that PFC. Rather, the intent is to set a target PFC that acts as a reference point. Manufacturers who choose to conduct on-track testing to certify their vehicles can use test surfaces with any PFC below the specified level to ensure compliance at the specified level. On the other hand, NHTSA, and laboratories conducting compliance tests, would use surfaces having a PFC at or above the target PFC to allow a reasonable margin for friction variations and other test surface variables.

This approach of specifying PFC without tolerance is consistent with how surface peak friction coefficients are specified in FMVSS No. 121, ''Air Brake Systems,'' FMVSS No. 135, ''Light Vehicle Brake Systems,'' and in FMVSS No. 126, ''Electronic Stability Control Systems. FMVSS No. 126 mandates Electronic Stability Control (ESC) systems on light vehicles, and establishes test procedures to ensure that ESC systems meet minimum requirements. In the rulemaking that established FMVSS No. 126, NHTSA originally proposed a tolerance around the surface PFC specification, but ultimately specified a single PFC for the test surface in the final rule. The agency explained that, although the proposed tolerance was an attempt to increase objectivity, such a tolerance created the possibility of compliance tests for FMVSS No. 126 being performed on lower friction coefficient surfaces than those for other braking standards, which is not the intention. NHTSA explained that while it is unlikely that any facility has a surface with exactly that friction coefficient, compliance testing for other braking standards is performed on a surface with a PFC slightly higher than the specification, which has more adhesion and creates a margin for clear enforcement. Here, as in the ESC final rule, NHTSA will use consistent compliance test conventions across all FMVSSs when specifying surface PFC.

Slope

This final rule adopts the proposed specification that NHTSA's test surface will have a consistent slope between 0 and 1 percent. The slope of the road surface can affect the performance of an AEB-equipped vehicle.[154] The slope also influences the dynamics and layout involved in the AEB test scenarios.

Comments

MEMA and Bosch commented, suggesting language from FMVSS No. 135 stating that the test surface has no more than a 1% gradient in the direction of testing and no more than a 2% gradient perpendicular to the direction of testing.

Agency Response

In response, NHTSA has not made the requested change. The agency's proposed specification did not specify that this is consistent in only the direction of travel. The agency might test on a surface that is not necessarily a defined lane, so, much like with ESC testing, the surface could be 1% in the direction of travel or normal to the direction of travel.

NHTSA provides the public with information on how the agency will conduct compliance tests, but manufacturers are not required to certify their vehicles using the tests in the FMVSS. Testing on a surface that is less flat could be more stringent, and manufacturers are free to test on a more stringent surface than what the agency

[151] Euro NCAP specifies visibility of at least 1 km (0.62 miles) and NHTSA's NCAP specifies 5 km (3.1 miles).

[152] ASTM E1337–19, *Standard Test Method for Determining Longitudinal Peak Braking Coefficient (PBC) of Paved Surfaces Using Standard Reference Test Tire.*

[153] 77 FR 51650 (Aug. 24, 2012).

[154] Kim, H. et al., *Autonomous Emergency Braking Considering Road Slope and Friction Coefficient,* International Journal of Automotive Technology, 19, 1013–1022 (2018).

uses.[155] Therefore, the agency does not see a need for the suggested change.

Markings

This final rule adopts the proposed specification that, in NHTSA's tests, within 2 m of the intended travel path, the road surface can be unmarked, or marked with one, or two lines of any configuration or color, at NHTSA's option. If lines are used, they must be straight, and, in the case of two lines, they must be parallel to each other and the distance between them must be from 2.7 m to 4.5 m. Vehicles equipped with AEB often are equipped with other advanced driver assistance systems, such as lane-centering technology, which detects lane lines. Those systems may be triggered by the presence of road markings, potentially leading to unrepeatable results.

Comments

In its comment, Bosch recommended including surface conditions such as grade lane markings, surrounding clearance areas, and acceptable target object specifications to enhance the accuracy and reliability of the testing process in each scenario. Zoox recommended specific markings for the regulation. It suggests text stating: ''The road surface within 2 m of the intended travel path is marked with two solid lines (yellow on the left, white on the right) that are straight, parallel to each other, and at any distance from 2.7 m to 4.5m.'' Zoox believes that, in the scenarios prescribed and with the variety of permissible lane markings, an ADS may drive around the obstruction instead of stopping in lane. It recommends specifying lane markings consistent with the Manual on Uniform Traffic Control Devices (MUTCD).

Agency Response

NHTSA disagrees with the recommendation by Bosch and Zoox to change the lane marking specifications for the compliance test. Fully marking the lane would simulate a vehicle traveling on new, well-marked roadways, which reduces the representativeness of test of the real-world. Lane markings across the country vary in terms of existence, quality, and placement. Many rural roads have little to no lane markings, older roads may have degraded or missing lane markings, and even new roadways may have lane markings that are not yet present. The provision that states that NHTSA has flexibility in how the lanes are marked puts manufacturers on notice that they must consider all roadway types when designing their AEB system, not just road with newly marked lines. The most commonly encountered lane marking colors are white and yellow; however, there are areas where vehicles may encounter other colors. The MUTCD states that markings are to be yellow, white, red, blue, or purple. Less common situations include E–ZPass lanes that are marked with purple/white lane markings. In general NHTSA does not believe that lane markings/colors have a technical effect on AEB performance, however specifying that lane lines used may be any color ensures that AEB performance will not vary based on lane marking color faded color.

NHTSA believes it is important to the real-world efficacy of AEB systems that AEB be designed to consider a wide variety of lane markings that it is reasonable to assume the systems may encounter in the real world. NHTSA is concerned that reducing the types of lane markings they need to consider would work against NHTSA's goals of ensuring the robustness of AEB systems and the safety benefits AEB can attain. Therefore, the agency will adopt the provisions described in the NPRM without change.

Subject Vehicle Conditions

This final rule adopts the proposed specification about the subject vehicle conditions during testing relating to the following topics: AEB initialization, tires, subject vehicle brakes, fluids and propulsion battery charge, user adjustable settings, headlamps and subject vehicle loading. Where the agency received no comments a particular topic, it is not discussed below. All proposals are adopted for the reasons discussed in the NPRM.

AEB System State and Initialization

In the NPRM, NHTSA proposed that testing not be conducted if the AEB malfunction telltale is illuminated or any of the sensors used by the AEB systems are obstructed. NHTSA proposed that AEB systems would be initialized before each series of performance tests to ensure the AEB system is in a ready state for each test trial. This is because the electronic components of an AEB system, including sensors and processing modules, may require a brief interval following each starting system cycle to reset to their default operating state. It also may be necessary for an AEB-equipped vehicle to be driven at a minimum speed for a period of time prior to testing so that the electronic systems can self-calibrate to a default or baseline condition, and/or for the AEB system to become active.

The proposed initialization procedure specifies that, once the test vehicle starting system is cycled on, it will remain on for at least one minute and the vehicle is driven at a forward speed of at least 10 km/h (6 mph) before any performance trials commence. This procedure also ensures that no additional driver actions are needed for the AEB system to be in a fully active state.

In its comment, Porsche suggested that vehicles should be brought to operating temperature before testing is begun. NHTSA disagrees with this suggestion for several reasons. First, it is NHTSA's position that the AEB system should be functional regardless of the vehicle's operating temperature because to choose otherwise could lead to unnecessary and concerning real-world limitations. The agency believes that specifying that the vehicle will be started and running for at least one minute prior to test initiation is more than sufficient for the manufacturer to have a functional AEB system. In the real world, vehicles often travel at the speeds proposed shortly after the driver powers the vehicle on. NHTSA requires brakes, lights, and crashworthiness devices, like seat belts and air bags, to work when the vehicle is turned on. In the same manner, the vehicle must meet FMVSS No. 127 when turned on. NHTSA is providing a brief initiation state for the AEB system to reset to a default operating state, but extending that state to the period suggested by Porsche would be contrary to the need for safety.

NHTSA believes the one-minute initiation period is generous in the context of the FMVSSs. There is a risk that drivers will not wait a minute to start driving. These drivers likely expect all vehicle system, especially safety systems, to be ready to operate once the vehicle is turned on. Porsche did not provide sufficient justification for its suggestion to extend that time. Based on these the above factors, NHTSA is not accepting Porsche's suggestion.

MEMA, Volkswagen, Porsche, and Bosch commented that the agency should adopt the pre-test conditioning process from UNECE Regulation No. 152 where, if requested by the manufacturer, the vehicle can be driven a maximum of 100 km (62.1 miles) to initialize the sensor system.

NHTSA also disagrees with this suggestion for the reasons discussed in the previous paragraph. This suggestion

[155] The manufacturer must exercise due care in making its certification. While manufacturers are not required to follow the tests in the FMVSSs, manufacturers seek to ensure that their vehicles will meet the FMVSS when NHTSA tests them according to the test procedures in the FMVSSs.

presents issues similar to those flagged in the previous paragraph, namely that the system should be available and functioning as soon as possible after vehicle start up and that a failure to do that could be very confusing to drivers and result in a failure to provide the safety benefits it should. For the reasons explained in this section, this final rule adopts the provisions proposed in the NPRM without change.

Brake Burnishing

To maximize test repeatability, this final rule adopts the proposed specification that subject vehicle brakes be burnished prior to AEB performance testing according to the specifications of either S7.1 of FMVSS No. 135, Light vehicle brake systems, which applies to passenger vehicles with GVWR of 3,500 kilograms or less, or to the specifications of S7.4 of FMVSS No. 105, which applies to passenger vehicles with GVWR greater than 3,500 kilograms. Since AEB capability relies upon the function of the service brakes on a vehicle, it is reasonable and logical that the same pre-test conditioning procedures that apply to service brake performance evaluations should also apply to AEB system performance evaluations.

Comments

In comments, MEMA, Volkswagen, Porsche, and Bosch suggest that the agency adopt the pre-test conditioning process from UNECE Regulation No. 152 in that the vehicle can undergo a series of brake activations to burnish the brake system.

Agency Response

In response, NHTSA agrees with commenters that properly burnishing the brake system is important, but NHTSA does not believe that it must adopt this aspect of UNECE Regulation No. 152 to accomplish that. NHTSA believes that the proposed brake burnishing procedures that are consistent with both FMVSS No. 135 and FMVSS No. 105 properly burnish the brake system, depending on the test vehicle's GVWR. Additionally, commenters did not provide NHTSA with any evidence that the brake burnishing procedures the agency proposed are improper for burnishing brakes or are otherwise unacceptable for any reason. NHTSA is not adopting the changes and will adopt the provisions proposed in the NPRM without change.

Brake Temperature

This final rule adopts the proposed specification that the subject vehicle service brakes be maintained at an average temperature between 65° C (149 °F) and 100° C (212 °F) measured as an average of the brakes on the hottest axle. This temperature range, which is the same as the range specified in FMVSS No. 135, is important for consistent brake performance and test repeatability.

Comments

In comments, MEMA, Volkswagen, Porsche, and Bosch suggest that NHTSA adopt the pre-test conditioning process from UNECE Regulation No. 152, specifically, that the average temperature of the service brakes on the hottest axle should be between 65–100 degrees C prior to each test run. Zoox also recommends that the hottest axle on the service brakes should be between 65–100 degrees C prior to testing, and that the agency should use FMVSS No. 135 as a guide for warming the vehicle brakes.

Agency Response

In response, NHTSA points out that the commenters refer to initial brake temperatures tested according to the procedure in FMVSS No. 135, and appear to be supporting NHTSA's proposed provisions notwithstanding reference to UNECE Regulation No. 152. The procedure in FMVSS No. 135 more rigorously specifies how and where temperature is measured than the equivalent in UNECE Regulation No. 152. NHTSA concurs and is adopting the provisions as proposed in the NPRM

User Adjustable Settings

This final rule adopts the proposed specification that NHTSA may test user adjustable settings such as engine braking, regenerative braking, and those associated with FCW, at any available setting state. Furthermore, adaptive and traditional cruise control may be used in any selectable setting during testing. The agency may test vehicles with any cruise control or adaptive cruise control setting to make sure that these systems do not disrupt the ability of the AEB system to stop the vehicle in crash imminent situations. However, for vehicles that have an ESC off switch, NHTSA will keep ESC engaged for the duration of the test.

Comments

In its comments, HATCI stated that NHTSA should test the vehicles using the default settings to represent real-world driving conditions because HATCI's research indicates that consumers do not typically change the settings. Bosch commented that the regenerative brakes add too much variability to the vehicle performance. Therefore, Bosch stated that the regenerative braking feature of a car, if equipped with one, should be overridden for the duration of AEB testing. AAA expressed concern that the proposal to allow vehicle testing with any cruise control setting would introduce too many variables into the testing scenario. AAA recommended the agency test all vehicles with the latest AEB setting and/or test all vehicles with and without the cruise control activated.

Agency Response

The purpose of the ''any'' user adjustable parameter is to ensure that driver-activated settings do not negatively impact AEB performance. NHTSA seeks to avoid a situation where use of a setting reduces the requisite performance of AEB when tested according to the parameters of S7, S8, and S9. NHTSA also sought to incorporate the word ''any'' into the standard to make clear that NHTSA has wide latitude to adjust the settings in a compliance test, in accordance with 49 CFR 571.4. That section states: ''The word *any,* used in connection with a range of values or set of items in the requirements, conditions, and procedures of the standards or regulations in this chapter, means generally the totality of the items or values, any one of which may be selected by the Administration for testing, except where clearly specified otherwise.''

NHTSA did not receive any comments indicating that the agency's approach to ensure AEB performance would be problematic. Vehicle manufacturers will have to assure that their designs do not negative affect the performance of AEB and may have more of a certification burden to assure such performance. The burden is reasonable, though, to assure that AEB systems work properly when other systems are engaged. Therefore, the agency is adopting the provisions proposed in the NPRM without change.

Loading

This final rule adopts the proposed specification that NHTSA will load the subject vehicle with not more than 277 kg (611 lbs.), which includes the sum of any vehicle occupants and any test equipment and instrumentation. The agency proposed this specification for load because tests of the fully loaded vehicles are already required and conducted under exiting FMVSSs, such as FMVSS No. 135, ''Light vehicle brake systems,'' to measure the maximum brake capacity of a vehicle.

Comments

NHTSA received comments from MEMA and ASC recommending that the agency harmonize with procedures of UNECE R151 and R152, and Euro NCAP. Those procedures specify a maximum load of 200 kg.

Agency Response

In response, NHTSA declines to adopt the suggested change. NHTSA derives the subject vehicle load of 277 kg (611 lbs.) from agency testing, which uses the provision in NHTSA's NCAP test procedures. Most, if not all, vehicle manufacturers are familiar with NCAP's procedures and have designed their vehicles in accordance with them. As explained in the NPRM, the stopping performance of a fully loaded vehicle is already assessed under FMVSS No. 135. Commenters supporting the UN Regulations maximum load of 200 kg gave little technical support or rationale as to why that maximum load was preferred to the 277 kg proposed load. It is not apparent to NHTSA whether or the degree to which the 77 kg difference would change the test results. Therefore, given the information available to the agency, NHTSA is adopting the proposal.

L. Vehicle Test Device

This final rule adopts specifications for a VTD to be used for compliance testing for the lead vehicle requirements. The GVT is a full-sized harmonized surrogate vehicle developed to test crash avoidance systems. To ensure repeatable and reproducible testing that reflects how a subject vehicle would be expected to respond to an actual vehicle in the real world, the VTD specified in this final rule will be used as a lead vehicle, pass through vehicle, and obstructing vehicle during testing. This final rule adopts all the specifications in the NPRM.

This final rule specifies that the vehicle test device is based on certain specifications defined in ISO 19206–3:2021, ''Road vehicles-Test devices for target vehicles, vulnerable road users and other objects, for assessment of active safety functions—Part 3: Requirements for passenger vehicle 3D targets.'' [156] The vehicle test device is a tool that NHTSA will use in compliance tests to measure the performance of AEB systems required by FMVSS No. 127.

1. General Description

In the NPRM, NHTSA provided background on the agency's purpose and rationale for proposing the VTD.[157] The VTD provides a sensor representation of a passenger motor vehicle. The rear view of the vehicle test device contains representations of the vehicle silhouette, a rear window, a high-mounted stop lamp, two taillamps, a rear license plate, two rear reflex reflectors, and two tires.

NHTSA received several comments on the proposed test device, all of which were generally supportive. Bosch, AAA, Rivian, the Alliance, and Ford all generally supported use of the proposed GVT across all AEB systems. AAA stated that the GVT is easy to use and provides versatility that allows for the evaluation of many realistic vehicle interaction. Rivian recommended NHTSA align the GVT device with the device used by Euro NCAP.

Forensic Rock, on the other hand, recommends higher speed targets that can withstand high closing speed tests with minimal damage to the vehicles. In response, NHTSA will continuously monitor the development of AEB technologies and test devices associated with system performance. If a need arises for new test devices, NHTSA can assess and respond to the situation at that time.

2. Definitions

The proposal defined a ''vehicle test device'' as a test device that simulates a passenger vehicle for the purpose of testing AEB system performance and defined a vehicle test device carrier as a movable platform on which a lead vehicle test device may be attached during compliance testing.

Bosch recommended the definition of ''vehicle test device'' be changed to ''a test device with the appearance and radar characteristics that, together with the vehicle test device carrier, simulates a passenger vehicle for the purpose of testing automatic emergency brake system performance.''

In response, NHTSA has considered the difference in the proposed definition for the ''vehicle test device'' and the definition suggested by Bosch and believes there to be no utility difference. The definition suggested by Bosch contains two areas of distinction from that of the proposed rule. First, Bosch suggested adding the phrase ''with the appearance and radar characteristics.'' While the specifications contain appearance and radar characteristics, such details are not needed within the definition to fulfill the purpose of a definition, which is to provide clarity as to what items are included and excluded from the term. The agency has decided to keep the definition broad and specify the technical details in the body of the regulation.

Second, the definition suggested by Bosch provides that only the combination of the vehicle test device and the vehicle test device carrier represent a passenger vehicle. While the specifications provide details of the carrier device, those details are minimal and are primarily designed to minimize the carrier's appearances. One limitation of Bosch's suggestion would be that only the combination of the vehicle test device and the carrier would be usable for testing at a definition level. Not all tests require movement of the vehicle test device and as such, these tests could be conducted without a carrier (provided that the vehicle test device meet the specifications without the carrier). Considering that the appearance of the carrier is to be minimal, such flexibility of testing provides advantages for compliance testing. Accordingly, the agency is finalizing the definition of vehicle test device as proposed in the NPRM.

3. Sideview Specification

NHTSA proposed to establish specifications applicable to only the rear-end of the vehicle test device. The proposal sought comment on whether the specifications for the vehicle test device should include sides of the vehicle, as well as the rear-end, and proposed potentially including the specifications from ISO 19206–3:2021.

Comments

Advocates, MEMA, ZF, and Bosch all support specification of sideview, so the AEB can address cross traffic in the future. MEMA and ZF also recommend angled rear view (30 degrees, for example) representing a vehicle making a right-hand turn. Advocates suggested that any shortcomings established with specifications of rear view should also be addressed by NHTSA for side view. Bosch stated that for test cases in which the sides of the vehicle are within the signal detection of the radars and/or sensors, the sides need to be included.

Agency Response

In response, NHTSA is not adopting turning scenarios or other scenarios where the side of the vehicle test device is critical to the outcome of the test. All lead vehicle scenarios, with the single exception of the false activation pass-through test, align the subject vehicle with the vehicle test device longitudinally along each centerline. Similar to the pass-through test, the obstructed pedestrian test that utilizes the vehicle test device aligns the subject

[156] *https://www.iso.org/standard/70133.html.* May 2021.

[157] 88 FR 38632 at 38705.

vehicle with vehicle test device longitudinally, with offsetting centerlines. Thus, no tests finalized in this final rule are dependent on the side view characteristics of the vehicle test device. If, in the future, tests are added that include side view interactions, the agency will consider additional specifications to the vehicle test device. For this final rule, the agency has finalized the rear-view characteristics only and has not added any view characteristics other than 180 degrees.

4. Field Verification Procedure

The NPRM did not specify in-the-field verifications be performed to assess whether the radar cross section falls within the acceptability corridor throughout the life of the device. NHTSA sought comment regarding the adoption of the optional field verification procedure provided in ISO 19206–3:2021, Annex E, Section E.3.

Comments

Bosch commented in support of the utilization of the optimal field verification procedure provided in ISO 19206–3:2021, Annex E, Section E.3, and further suggests the inclusion of suitable parts of the Annex C.

Agency Response

In response, the field verification procedure is not included in this final rule. NHTSA testing has shown that the radar cross section of a new GVT and a ''used'' GVT manufactured by at least one company fall consistently within the specified corridor incorporated by reference from ISO 19206–3:2021.[158] The field verification procedure alone does not fully demonstrate that the vehicle test device is within the specifications outlined in this rule. Accordingly, while the agency may informally use the field verification test to provide a general indication of the state of the vehicle test device, such a procedure is not appropriate for the test procedure.

5. Dimensional Specification

NHTSA proposed that the rear silhouette and the rear window be symmetrical about a shared vertical centerline and that representations of the taillamps, rear reflex reflectors, and tires also be symmetrical about the surrogate's centerline. Further, the license plate representation was proposed to have a width of 300 ± 15 mm and a height of 150 ± 15 mm, and be mounted with a license plate holder angle within the range described in 49 CFR 571.108, S6.6.3.1. Lastly, NHTSA proposed that the VTD representations be located within the minimum and maximum measurement values specified in columns 3 and 4 of Table A.4 of ISO 19206–3:2021 Annex A. The tire representations are to be located within the minimum and maximum measurement values specified in columns 3 and 4 of Table A.3 of ISO 19206–3:2021 Annex A. Additional clarification of terms was included in the NPRM stating that ''rear light'' means ''taillamp,'' ''retroreflector'' means ''reflex reflector,'' and ''high centre taillight'' means ''high-mounted stop lamp.''

Comments

In their comments, Ford, Porsche, and FCA all agree with NHTSA that the vehicle test device should be based on specifications defined in ISO 19206–3:2021. AAA and Adasky, alternatively, suggests that NHTSA re-assess the proposed requirement to be consistent with subcompact and compact cars, given the increased popularity of larger crossovers, SUVs, and light-duty trucks. Adasky recommends that the influences of hood height and A-pillar be included in the vehicle test device property definition.

Agency Response

In response, NHTSA has adopted the specification as proposed. Most commentors agreed with the use of ISO 19206–3:2021, which NHTSA proposed as appropriate in the NPRM. The agency does not have information to support adopting a change at this time. The agency would also point out that including the hood height and A pillar is unnecessary for front to rear crashes because they are not visible from the rear of the test device, which is the orientation for all tests.

6. Visual and Near Infrared Specification

NHTSA proposed that the vehicle test device rear representation colors be within the ranges specified in Tables B.2 and B.3 of ISO 19206–3:2021 Annex B. The proposal also specified that the infrared properties of the vehicle test device be within the ranges specified in Table B.1 of ISO 19206–3:2021 Annex B for wavelengths of 850 to 950 nm when measured according to the calibration and measurement setup specified in paragraph B.3 of ISO 19206–3:2021 Annex B. Lastly, NHTSA proposed that the rear reflex reflectors, and at least 50 cm^2 of the taillamp representations, of the vehicle test device be grade DOT–C2 reflective sheeting as specified in 49 CFR 571.108, S8.2.

NHTSA received no comments on this proposal. The agency has adopted the provision for the reasons provided in the NPRM.

7. Radar Reflectivity

NHTSA proposed that the radar cross section of the vehicle test device is to be measured while attached to the carrier (robotic platform). NHTSA also proposed that the radar reflectivity of the carrier platform be less than 0 dBm^2 for a viewing angle of 180 degrees at a distance of 5 to 100 m, when measured according to the radar measurement procedure specified in C.3 of ISO 19206–3:2021 Annex C for fixed-angle scans. The proposal also stated that the rear bumper area, as shown in Table C.1 of ISO 19206–3:2021 Annex C, contributes to the target radar cross section. NHTSA proposed that the radar cross section be assessed using a radar sensor that operates at 76 to 81 GHz and has a range of at least 5 to 100 m, a range gate length smaller than 0.6 m, a horizontal field of view of 10 degrees or more (–3dB amplitude limit), and an elevation field of view of 5 degrees or more (–3dB amplitude). The proposal stated that a minimum of 92 percent of the filtered data points of the surrogate radar cross section for the fixed vehicle angle, variable range measurements be within the radar cross section boundaries defined in Section C.2.2.4 of ISO 19206–3:2021 Annex C for a viewing angle of 180 degrees when measured according to the radar measurement procedure specified in C.3 of ISO 19206–3:2021 Annex C for fixed-angle scans. Lastly, the proposed rule stated that between 86 to 95 percent of the vehicle test device spatial radar cross section reflective power be within the primary reflection region defined in Section C.2.2.5 of ISO 19206–3:2021 Annex C, when measured according to the radar measurement procedure specified in Section C.3 of ISO 19206–3:2021 Annex C using the angle-penetration method.

Comments

In their comments, ZF and ASC both consider the tolerance of +/− 10dBm^2 to be quite high. ZF noted that information derived might be misleading (*e.g.,* object classification). In addition, ZF, ASC, Mobileye, and MEMA recommend including acceptable Radar Cross Section (RCS) ranges for the rear and the side of the VTD. While ZF, ASC, and MEMA suggest using the same RCS corridor values as specified in ISO 19206–3:2021, Mobileye suggests setting the bars at the lower RCS values (*e.g.,* –10dBsm for VRU, 0dBsm or below for

[158] Assessing the Effect of Wear on Vehicle Test Device Radar Return Characteristics, available in the docket for this final rule (NHTSA–2023–0021).

motorcycle). Mobileye also suggests including lateral edge errors as critical metrics because identifying the lateral edges of the object lowers risk of false association with camera or other sensors. Bosch recommends amending the radar reflectivity specifications because, ''The radar reflectivity of the carrier platform alone is less than 0 dBm^2 for a viewing angle of 180 degrees and over a range of 5 to 100 m when measured according to the radar measurement procedure specified in Section C.3 of ISO 19206–3:2021 Annex C for fixed-angle scans.''

Agency Response

The agency disagrees with the suggested revision to the radar reflectivity for the carrier, as the carrier radar characteristics are important when attached to the VTD, not the carrier by itself for the purposes of testing AEB. Testing the carrier alone fails to take into account the actual interface between the VTD and the carrier system.

Regarding the RCS range, the agency believes that both values are needed to set appropriate bounds of what is acceptable RCS for the VTD to match real world vehicles. The vehicle tests using two different sensors documented in the ISO 19206–3:2021 Figure C.17 and C.18 show that the vehicles tested varied within +/− 10dBm^2. Thus, permitting the vehicle test device to vary within this tolerance provides real-world application for the various vehicles on the road. In addition, lateral error tolerances are included in the test set-up specifications.

NHTSA is not adding turning scenarios to this proposal, and therefore the agency believes that side presentation specifications are not needed. NHTSA is finalizing the radar reflectivity specifications for the vehicle test device as proposed in the NPRM.

8. List of Actual Vehicles

In addition to the vehicle test device specifications, NHTSA sought comment on specifying a set of real vehicles to be used as vehicle test devices in AEB testing. NHTSA also sought comment on the utility and feasibility of safely conducting AEB tests with real vehicles, such as through removing humans from test vehicles and automating scenario execution, and how laboratories would adjust testing costs to factor in the risk of damaged vehicles. Additionally, NHTSA sought comments on the merits and potential need for testing using real vehicles, in addition to using a vehicle test device, as well as challenges, limitations, and incremental costs of such.

Comments

Advocates and Bosch both generally support the development of a list of possible real vehicles that could be used for testing in addition to the GVT. While Bosch suggests that NHTSA reference the relevant parts of ISO 19206–3:2021 if using a set of real vehicles, Advocates recommend that NHTSA consider the most frequently registered vehicles in the US over some lookback period with an established timeline.

In contrast, Rivian, Alliance, ASC, ZF, and MEMA all oppose using real vehicles. ZF, MEMA, and ASC state high cost and risk of injury to human subjects in performing high-speed AEB tests. ASC and ZF added that the advantages of testing with real vehicles compared to soft vehicle targets is not clear. Furthermore, ZF and MEMA mention that the tests that involve a soft target could serve as a real vehicle test if combined with documentation provided by the OEM.

The Alliance notes test repeatability and reproducibility challenges due to potential differences in vehicles selected for testing and that repairs may be expensive and time-consuming if contact occurs. It also notes that the current GVT is correlated to real world vehicles through collaborative global government/industry testing and verification. Rivian stated that using representative test devices, as opposed to real vehicles, reduces test burdens on manufacturers and poses lesser risk of injury if AEB fails to avoid a crash during the test procedure. ASC and ZF believe that vehicles with AEB systems should be able to detect a wide range of vehicles and suggests that if NHTSA decides to develop its own, more US-fleet representative GVT target, then it should be compliant with the ISO standard.

Agency Response

NHTSA agrees that the VTD specifications provide sufficient flexibility in appearance that creating a list of vehicles for testing is not likely to increase the safety impacts of the rule. NHTSA also agrees that there are concerns over the cost of testing with real vehicles, and, that there are potential safety risks to test operators. NHTSA believes that the GVT is representative of a genuine vehicle,[159] and does not believe that the increased costs of adding a documentation requirement for manufacturers to show this is warranted at this time. Accordingly, the agency is not adopting a list of real vehicles for testing at this time.

M. Pedestrian Test Devices

This final rule adopts specifications for two pedestrian test devices to be used for compliance testing for the PAEB requirements. The two pedestrian test devices each consist of a test mannequin and a motion apparatus (carrier system) that positions the test mannequin during a test. NHTSA's specifications for pedestrian test mannequins represent a 50th percentile adult male and a 6- to 7-year-old child. NHTSA has incorporated by reference specifications from three ISO standards.

1. General Description

The Adult Pedestrian Test Mannequin (APTM) provides a sensor representation of a 50th percentile adult male and consists of a head, torso, two arms and hands, and two legs and feet. The Child Pedestrian Test Mannequin (CPTM) provides a sensor representation of a 6- to 7-year-old child and consists of a head, torso, two arms and hands, and two legs and feet. The arms of both test mannequins are posable but will not move during testing. The legs of the test mannequins will articulate and will be synchronized to the forward motion of the mannequin.

In the NPRM, NHTSA provided background on the agency's purpose and rationale for proposing the test devices and the history of the devices and their use,[160] including previous NHTSA **Federal Register** notices that have solicited input from the public on test procedures that include the use of these pedestrian test devices either in current or past form (*i.e.,* articulated vs. non-articulated legs).

NHTSA received many comments on the proposal, all of which were generally supportive. Commenters generally supported the use of the ISO 19206–2:2018 mannequins as these are already validated and readily available. SAE noted that its mannequin prototypes had limited testing in the test track and deferred to NHTSA's understanding of the new standard to know which pedestrian mannequin would be most appropriate for the regulation. The commenters also supported harmonizing with international standards, such as UNECE Regulation No. 152, as a baseline for mannequin specifications, and with ISO

[159] Overall, the AEB system sensors interpret the SSV appears to sensors as a genuine vehicle. Nearly all vehicle manufacturers and many suppliers have assessed how the SSV appears to the sensors used for their AEB systems. The results of these scans have been very favorable. 80 FR 68615, NCAP RFC, Docket No. NHTSA–2015–0006.

[160] 88 FR at 38702.

19206–2:2018 regarding the PAEB mannequins.

In response, NHTSA is adopting the relevant parts of ISO 19206–2:2018 and ISO 19206–4:2020, as specified in the NPRM. ISO 19206 has a larger body of research testing to support its test devices than SAE J3116, and using ISO 19206 is consistent with international standards like UNECE Regulation No. 152.

For the mannequin carrier system, Bosch suggested adoption of the ISO 19206–7 specifications and test hardware to specify the carrier system used to move the pedestrian test mannequin. Bosch further recommended revising the definitions of the adult and child mannequins to refer to the carrier systems. NHTSA is declining to make these changes. Because ISO 19206–7 is still in draft form, NHTSA believes it is premature to consider it for adoption. Regarding the carrier system, it is a modular system designed to move the child and adult test mannequins. As such, NHTSA believes that the definition of the carrier system should lie outside the definition of either mannequin. It is also more appropriate to specify how the carrier system can affect sensor representations of the mannequins, rather than specify it as part of a mannequin.

The American Foundation for Blind (AFB) recommended NHTSA use the most inclusive and effective mannequins that will reduce road injuries and deaths among people with disabilities, including women, adults with short stature, and cyclists. Some commenters suggest that NHTSA use pedestrian test mannequins using mobility assistive devices, such as wheelchairs (motorized and non-motorized), walkers, motorized scooters, or canes.

In response, NHTSA is interested in additional pedestrian test devices outside of the child and adult pedestrian test mannequins, including those that reflect the broad diversity among the American public. At this time, however, there is a need for more development, research, and testing for pedestrian test mannequins that are using mobility assistive devices. NHTSA intends to monitor the progress of these devices as they are developed and standardized, for possible inclusion in the standard at a future date.

2. Dimensions and Posture

The APTM and the CPTM have basic body dimensions and proportions specified in ISO 19206–2:2018. All commenters responding to the proposed dimensions agreed with the proposal. The agency is adopting the proposal for the reasons provided in the NPRM.

A number of commenters responded to NHTSA's question asking whether use of the 50th percentile adult male test mannequin would ensure PAEB systems will react to small adult females and other pedestrians other than mid-size adult males. Consumer Reports (CR) supported NHTSA's proposal to use a pedestrian test mannequin representing a 50th-percentile adult male and one representing a six- to seven-year-old child, stating it is critical to use both mannequins in PAEB testing to account for a range of human proportions. The commenter believed it is especially important to use the child mannequin to provide adequate protection for children and other shorter individuals, particularly from impacts involving large vehicles that have tall hoods or that otherwise have limited frontal visibility.

Several commenters (Advocates, AARP, ZF, Consumer Reports, and MEMA) suggested including an adult female mannequin and the child mannequin in all tests. NHTSA is unaware of any standards providing specifications for a 5th percentile adult female test mannequin, or of any consumer information programs testing with such a device.

The Alliance stated that the proposed child and adult test devices should provide a reasonable assessment across a broad spectrum of occupant sizes.[161] AAA recommended not including the child test mannequin for all testing scenarios, as this would increase testing burdens. AAA suggested that, as an alternative, NHTSA could test some scenarios with the smaller SAE pedestrian test mannequin.

After reviewing the comments, NHTSA is satisfied that the currently proposed pedestrian test mannequins provide a reasonable representation of the pedestrian crash population for purposes of issuing this final rule. In its comment to the NPRM, IIHS stated that evidence does not demonstrate that current PAEB systems are tuned only to the adult male mannequin. This rulemaking does not expand the mannequins used in new FMVSS No. 127, or expand how the child dummy is used, because NHTSA does not have the body of research necessary to support such changes for this final rule.

FCA noted that there are no dimensional tolerances on the pedestrian test device. In response, NHTSA's testing has not shown an issue with the dimensions specified in the NPRM. Further, the locational bounds of the pedestrian test mannequin are specified in the individual test scenarios. Thus, the agency is not adopting additional tolerances on the dimensional specification of the pedestrian test mannequins. SAE responded to NHTSA's comment on shoe height, stating that the overall mannequin height on the sled is representative of the overall height of real pedestrians with shoes.

3. Visual Properties

The mannequins will have specified features for the depictions of hair, skin tone, clothing, and the like. The features are specified in the ISO standards incorporated by reference into FMVSS No. 127 by this final rule. The incorporated ISO standards provide needed specifications for these features, but they also allow NHTSA to harmonize with specifications for test mannequins in use by Euro NCAP.

Because specifications for test mannequin skin color are not found in ISO 19206–2:2018, NHTSA is incorporating by reference the bicyclist mannequin specifications for color and reflectivity found in ISO 19206–4:2020, ''Road vehicles—test devices for target vehicles, vulnerable road users and other objects, for assessment of active safety functions—Part 4: Requirements for bicyclists targets.'' Although this standard provides requirements for bicyclist test devices, NHTSA is referencing it for color and reflectivity for the prescribed adult and child test mannequins because the specifications are workable for use with the ISO standard for pedestrian test devices. NHTSA is specifying that the test mannequins be of a color that matches a specified range of skin colors representative of very dark to very light complexions. The mannequins must also have standardized properties that represent hair, facial skin, hands, and other features, and must have a standardized long-sleeve black shirt, blue long pants, and black shoes.

Commenters (AARP, Safe Kids Worldwide (SKW), Safe Kids in Autonomous Vehicles Alliance (SKAVA), Luminar, and private citizens) supported NHTSA's effort to ensure PAEB detect pedestrians of all skin colors. The agency agrees with the commentors that sensors should detect skin tones other than light skin tones.

Luminar did not support the white face, black shirt, and blue pants on mannequins. While NHTSA understands that the commenter would like to see testing outside of the

[161] The Alliance supported using a child test mannequin in daytime scenarios only, and not also in the nighttime scenario. NHTSA discussed this comment in separate section.

specifications identified in the NPRM, the agency does not have the body of knowledge necessary to objectively specify clothing outside of the black shirt and blue pants. Furthermore, commenters did not provide data demonstrating that current PAEB systems do not already detect a wide array of skin tones. The proposal includes a range of colors (based on ISO 19206–4_2020 standard) for skin, face, and hands. NHTSA encourages manufacturers to consider designing their systems to detect all pedestrians, including those wearing various clothing colors.

4. Radar Properties

The radar reflectivity characteristics of the pedestrian test device approximates that of a pedestrian of the same size when approached from the side or from behind. Radar cross section measurements of the pedestrian test mannequins must fall within the upper and lower boundaries shown in Annex B, section B.3, figure B.6 of ISO 19206–2:2018 when tested in accordance with the measure procedure in Annex C, section C.3 of ISO 19206–2:2018.

In response to Bosch, this final rule adopts the newer ISO 19206–3:2021 instead of ISO 19206–2:2018 in determining the upper and lower boundaries for an object for radar cross-section measurements. The proposed procedure in Annex C, section C.3 of ISO 19206–2:2018 is specific for pedestrian targets; however, recent testing performed by the agency indicates that the three position measurement specified in Annex C, section C.3 of ISO 19206–3:2021 provides more reduction in multi-path reflections and offers more accurate radar cross section values. This testing confirms the recommendation from Bosch to adopt the measurement procedure in Annex C, section C.3 of ISO 19206–3:2021. Therefore, the agency is adopting the new version of the ISO standard.

5. Articulation Properties

This final rule adopts the proposal that the legs of the pedestrian test device be in accordance with, and as described in, Annex D, section D.2 and illustrated in Figures D.1, D.2, and D.3 of ISO 19206–2:2018. For the test scenarios involving a moving pedestrian, the legs of the pedestrian test mannequin will articulate to simulate a walking motion. A test mannequin that has leg articulation when in motion more realistically represents an actual walking or running pedestrian. For test scenarios involving a stationary pedestrian, the legs of the pedestrian test mannequin remain at rest (*i.e.,* simulate a standing posture).

Commenters to this issue supported the pedestrian test mannequin with articulation characteristics. The Alliance agreed that mannequins equipped with articulate moving legs are more representative of actual pedestrians than mannequins with stationary legs. While agreeing with the NPRM, Aptiv noted that even when people are standing next to a road, they move in some way (*e.g.,* body micro-movement) and so NHTSA may want to add some upper body movement to the stationary pedestrian test mannequin. Porsche supported the adoption of articulated dummies, explaining that the articulated motion is required because of the ''micro doppler'' effect, which is an important consideration for radar sensors.

NHTSA has adopted the proposal for the articulation properties of the legs. The agency is not adding pedestrian micro-movement to the articulation requirements as there are currently no consensus standards available for pedestrian micro-movement and NHTSA does not testing experience with mannequins of that type.

6. Comments on Thermal Characteristics

In addition to the characteristics specified in the proposal presented in the NPRM, NHTSA requested comments on whether test mannequins should have thermal characteristics. Several commenters [162] responding to the NPRM discussed the merits of thermal characteristics in the pedestrian test mannequins. Owl AI and Teledyne explained that thermal imaging can capture infrared radiation emitted by pedestrians in the 8–14μm (long wave) band, which allows for pedestrians to be easily distinguished from other objects. AAA supported inclusion of thermal specifications, especially for nighttime testing.

NHTSA currently does not have the body of research necessary to develop test protocols that support the inclusion of thermally active pedestrian test mannequins but concurs this matter may be a topic for future consideration. NHTSA will continue to monitor the development of thermally active pedestrian test mannequins so that the agency can explore their use in the future.

N. Miscellaneous Topics

Advocates, ZF, AAA, Rivian, Volkswagen, AARP, the National Associations of Mutual Insurance Companies, and ASC suggested a requirement that vehicle manufacturers provide information in owners' manuals and elsewhere describing how the AEB system works, and its capabilities and its limitations. SEMA suggested a requirement that specific information such as diagnostic codes and calibration information be shared with consumers, MEMA suggested web links to information, and NADA suggested using a QR code on the Monroney label. SEMA also requested that NHTSA provide a system of information about AEB to aftermarket suppliers.

In contrast, the Alliance and Hyundai opposed new information requirements about AEB, suggesting that information is already provided in the absence of a regulation. Additionally, the Alliance stated it is unaware of the safety impacts of providing AEB information to consumers.

This final rule has not adopted additional information requirements. The agency concludes that the primary safety impacts from AEB is the functionality itself. While information regarding the capabilities and limitations of the AEB system may be generally useful, AEB as required by this rule is a last second intervention system. Thus, a driver's basic driving technique should not change based on the capabilities or even the existence of AEB (aside from heeding the warning of the malfunction indicator to attend to a problem with the AEB system).

FCA believed that the proposed requirements overly focus performance on the vehicle's braking system and not on the output of the sensing and perception capacity of the AEB system. FCA further stated that it could be possible to focus the regulatory requirement solely onto the AEB system (*i.e.,* the sensors and perception system) by defining a perception mandate for output signals for time to warn or the BRAKE! Command. FCA further asserted that this output could be derived from fleet averages, equations of motion, and that as vehicle performance improves, the timing could be revised accordingly.

In response, NHTSA declines FCA's suggestion to directly regulate the sensing and perception systems directly instead of the ability of the entire system to avoid crashes. This FMVSS is created with important safety goals in mind to address significant safety problems that this technology can resolve. For this rule, the safety problems are rear-end crashes and crashes involving pedestrians struck by the front of a vehicle. The performance requirements (avoiding contact with a lead vehicle and pedestrian) address

[162] Commenters included Advocates, Adasky, Owl AI, Teledyne, and AAA.

this safety problem in an effective and expeditious manner. They are solidly supported and informed by data from years of agency and industry research, the voluntary commitment and NCAP, substantial collaborative work between entities, and NHTSA's close monitoring of AEB development and maturation. A new approach specifying a particular time to collision based on the information from the perception system is not supported by the current stated of knowledge and would take years to research and develop.

FCA commented that NHTSA did not provide a baseline or compliance assessment of the front lighting equipment installed in the research vehicles, so manufacturers are unaware of the performance level of the lighting relative to the FMVSS No. 108 range. For example, the vehicles may have been equipped with optional lighting packages within the product lineup, which may have enhanced performance. FCA also noted that lighting was not included in the technical assessment or economic analysis in the proposal. FCA expressed that NHTSA should have knowledge regarding the high cost of modern lighting systems and importantly, how much lead time would be needed to develop them, and that performance requirements should not prohibit otherwise compliant lighting systems. Finally, it stated that if improved lighting is mandatory for AEB nighttime performance objectives, FMVSS No. 108 should be reconfigured in a separate rulemaking.

In response, NHTSA's performance-oriented approach in this final rule directly addresses the safety problem while providing manufacturers the most flexibility in designing vehicles to meet FMVSS No. 127. Improved lighting is not a requisite of the final rule. A manufacturer may choose to create a robust perception system that initiates braking sooner, have a lesser performing perception system and equip the vehicle with robust brakes, have a high performing headlighting system to help achieve the performance required, or implement another means of meeting the standard. Because FMVSS No. 127 is a performance standard, manufacturers decide what countermeasures makes the most sense for them to meet the standard, and the marketplace can continue to drive innovation while achieving positive safety outcomes.

O. Effective Date and Phase-In Schedule

NHTSA proposed that all requirements be phased in within four years of publication of a final rule. Under the proposal, all AEB-equipped vehicles would be required to meet all requirements associated with lead vehicle AEB within three years. NHTSA also proposed that all PAEB-equipped vehicles would be required to meet all daylight test requirements for PAEB within three years. For PAEB performance in darkness, NHTSA proposed lower maximum test speed thresholds that would have to be met within three years for some specified test procedures. Under the proposal, all vehicles would be required to meet the minimum performance requirements with higher darkness test speeds four years after the publication of a final rule. Small-volume manufacturers, final-stage manufacturers, and alterers would be provided an additional year of lead time for all requirements.

NHTSA requested comments on the proposed lead time for meeting the proposed requirements, and how the lead time can be structured to maximize the benefits that can be realized most quickly while ensuring that the standard is practicable.

Comments

In general, manufacturers, suppliers, and industry advocacy groups asserted that more time is needed to meet the performance requirements in the NPRM. In contrast, safety advocates and municipalities requested that the proposed requirements be implemented sooner.

More specifically, the Alliance cited concerns over the practicability of no contact, the NPRM's underestimation of the software and hardware changes needed to facilitate crash avoidance at higher speeds, and the complexity of addressing false positives all within a short lead time. They expressed that it cannot be known whether systems can achieve the proposed requirements through software upgrades until a comprehensive system review, analysis, and synthesis has been performed by manufacturers. Further, they expressed that the proposed timeline could disrupt vehicle developments already underway as it may require revisiting previous hardware and software design decisions and redesigning systems expected to impact or be impacted by the AEB/PAEB system. In addition, they stated that existing vehicle electrical architectures may not be capable of handling the additional or upgraded sensors, additional communication bandwidth and processing power to upgrade the vehicle ADAS system to the proposed level of performance.

The Alliance, Mitsubishi, Honda, and Nissan proposed a compliance date starting seven years or more after the issuance of a final rule for large volume manufacturers, and the Alliance suggested an additional four years for small volume manufacturers. The Alliance proposed an alternative compliance schedule that begins five years after the issuance of a final rule but noted that this would not address the outstanding technical issues and unintended consequences that they outlined in their comments.

Volkswagen and Porsche suggested a phased-in compliance process where a certain percentage of the fleet would be required to comply over a period of several years until 100 percent of the fleet was required to comply with the final rule. The Alliance and Nissan suggested that if the agency considered its proposal to harmonize with UNECE Regulation No. 152, compliance could occur sooner. Porsche and Volkswagen suggested that compliance with UNECE Regulation No. 152 could be considered for end-of-production lines or as part of a phase-in.

Bosch recommended a stepwise regulatory timeline, observing that speeds up to 60 km/h are achievable as proposed in the NPRM, but additional time would be necessary for testing at higher speeds. Mobileye suggested a similar approach.

Advocates stated that the agency should require a more aggressive schedule for compliance given the baseline inclusion of the components for AEB systems in new vehicles. In addition, Advocates stated that they oppose any further extension of the proposed compliance dates in the NPRM. The NTSB encouraged NHTSA to consider reducing the timeline for the rule's effective dates to expedite deployment as some manufacturers may be able to achieve some of the performance requirements immediately. Consumer Reports suggested that all requirements, other than darkness pedestrian avoidance requirements, be effective no later than one year after issuing a final rule. For darkness pedestrian avoidance requirements, Consumer Reports stated that NHTSA should set the compliance timeline at no more than two years after publication of a final rule. NAMIC and IIHS stated that, based on recent IIHS test data, manufacturers have made dramatic progress in PAEB programs in a short time, and recommended a one-year phase-in. Finally, NACTO, Richmond Ambulance Authority, DRIVE SMART Virginia, the city of Philadelphia, the city of Houston, and the Nashville DOT recommended that NHTSA have the higher speed pedestrian avoidance tests in dark conditions required on the same timeline as the daytime scenarios.

Agency Response

The agency finds the arguments for additional lead time compelling. For the reasons discussed below, this final rule requires that manufacturers comply with all provisions of this final rule at the end of the five-year period starting the first September 1 after this publication, or September 1, 2029. Most vehicles sold today do not meet all of the requirements set forth in this final rule, and many may not be easily made compliant with all of the requirements established in this final rule. While NHTSA recognizes the urgency of the safety problem, NHTSA also recognizes that the requirements of this final rule are technology-forcing. The agency believes that the requirements are crucial in ensuring the safety in the long run, but we are extending the schedule to avoid significantly increasing the costs of this rule by requiring that manufacturers conduct expensive equipment redesigns outside of the normal product cycle. Because of the normal product development cycle, it is likely that there will be significant market penetration of complying systems as they are developed prior to the effective date of this rule.

While some commenters suggested that the proposed lead time is practicable if the agency reduced the stringency of this final rule's requirements, such an approach would result in a substantial decrease in the expected benefits of this rule in the long run. A lead time of five years provides manufacturers with the ability to fully integrate the AEB system into vehicles in line with the typical design cycle in many cases. Such a process permits manufacturers to fully design systems that minimize the false activations that industry has expressed concern about, yet still provide the level of performance required by this rule. NHTSA believes a five-year lead time fully balances safety considerations, the capabilities of the technology, and the practical need to engineer systems that fully comply with this final rule.

Note that as discussed in the Regulatory Flexibility Act section of the document, NHTSA is giving certain small manufacturers and alterers an additional year of lead time to comply with this rule.

Safety Act

Under 49 U.S.C. 30111(d), a standard may not become effective before the 180th day after the standard is prescribed or later than one year after it is prescribed, unless NHTSA finds, for good cause shown, that a different effective date is in the public interest and publishes a reason for the finding. A 5-year compliance period is in the public interest because most vehicles will require upgrades of hardware or software to meet the requirements of this final rule. To require compliance with this standard outside of the normal development cycle would significantly increase the cost of the rule because vehicles cannot easily be made compliant with the requirements of this final rule outside of the normal vehicle design cycle.

IV. Summary of Estimated Effectiveness, Cost, and Benefits

The requirements specified in this final rule for Lead Vehicle AEB address rear-impact crashes. Between 2016 and 2019, an average of 1.12 million rear-impact crashes involving light vehicles occurred annually. These crashes resulted in an annual average of 394 fatalities, 142,611 non-fatal injuries, and approximately 1.69 million property-damage-only vehicles (PDOVs).

In specifying the requirements for Lead Vehicle AEB, the agency considered the number of fatalities and non-fatal injuries resulting from crashes that could potentially be prevented or mitigated given the current capabilities of this technology. As a result, the requirements specified for Lead Vehicle AEB consider the need to address this safety issue by ensuring that these systems have sufficient braking authority to generate speed reductions that can prevent or mitigate real-world crashes.

The requirements specified in the final rule for PAEB address crashes in which a light vehicle strikes a pedestrian. Between 2016 and 2019, an average of approximately 23,000 crashes that could potentially be addressed by PAEB occurred annually. These crashes resulted in an annual average of 2,642 fatalities and 17,689 non-fatal injuries.

In specifying the requirements for PAEB, the agency considered the number of fatalities and non-fatal injuries resulting from crashes that could potentially be prevented or mitigated given the current capabilities of this technology. As a result, the requirements specified for PAEB consider the need to address this safety issue by ensuring that these systems have sufficient braking authority to generate speed reductions that can prevent or mitigate real-world crashes with pedestrians.

The target population for the lead vehicle AEB analysis includes two-vehicle, rear-end light vehicle crashes and their resulting occupant fatalities and non-fatal injuries. FARS is used to obtain the target population for fatalities and CRSS is used to obtain the target population for property-damage-only crashes and occupant injuries. The target population includes two-vehicle light-vehicle to light-vehicle crashes in which the manner of collision is a rear-end crash and the first harmful event was a collision with a motor vehicle in transport. Further refinement includes limiting the analysis to crashes where the striking vehicle was traveling straight ahead prior to the collision at a speed less than 90.1 mph (145 km/h) and the struck vehicle was either stopped, moving, or decelerating.

Table 23: Light Vehicle to Light Vehicle Target Population

Light Vehicle to Light Vehicle Target Population	Crashes	PDOVs	Injuries						Fatalities
			MAIS1	MAIS2	MAIS3	MAIS4	MAIS5	MAIS 1-5	
All Conditions	1,119,470	1,692,678	130,736	9,364	1,942	256	57	142,611	394

The target population for the PAEB analysis considered only light vehicle crashes that included a single vehicle and pedestrian in which the first injury-causing event was contact with a pedestrian. The area of initial impact was limited to the front of the vehicle, specified as clock points 11, 12, and 1, and the vehicle's pre-event movement was traveling in a straight line.

These crashes were then categorized as either the pedestrian crossing the vehicle path or along the vehicle path. The crashes are inclusive of all light, road surface, and weather conditions to capture potential crashes, fatalities, and injuries in real world conditions. Data

elements listed as ''unknown'' were proportionally allocated, as needed.

Table 24: Target Population of Pedestrian Fatalities and Non-Fatal Injuries

Light Vehicle to Pedestrian Target Population	Injuries						Fatalities
	MAIS 1	MAIS 2	MAIS 3	MAIS 4	MAIS 5	MAIS 1-5	
All Scenarios	13,894	3,335	1,541	300	75	19,511	2,508
Crossing Path	12,637	3,087	1,442	284	71	17,522	2,083
Along Path	1,257	248	98	16	4	1,622	425

A. Benefits

As a result of the requirements for Lead Vehicle AEB and PAEB specified in this final rule, we estimate that 362 fatalities and more than 24,000 non-fatal MAIS 1–5 injuries will be mitigated over the course of one vehicle model year's lifetime.

Table 25: Summary of Benefits: Estimated Quantified Benefits for Non-Fatal Injuries and Fatalities Mitigated

Injury Severity	Lead Vehicle AEB	PAEB	Total
MAIS 1	18,449	2,089	20,538
MAIS 2	2,575	401	2,976
MAIS 3	536	153	689
MAIS 4	71	23	94
MAIS 5	18	6	24
Total MAIS 1-5	21,649	2,672	24,321
Fatal	124	238	362

MAIS - Maximum Abbreviated Injury Scale

B. Costs

The agency estimated the incremental costs associated with this final rule, which has been adjusted from the estimates presented in the NPRM to include the costs associated with software and hardware improvements, compared to the baseline condition. Incremental costs reflect the difference in costs associated with all new light vehicles being equipped with AEB with no performance standard (the baseline condition) relative to all light vehicles being equipped with AEB that meets the performance requirements specified in this final rule.

As common radar and camera systems are used across Lead Vehicle AEB and PAEB systems, functionality can be achieved through upgraded software for most of the affected vehicles. Therefore, the agency accounts for the incremental cost associated with a software upgrade for all new light vehicles. Although the majority of new light vehicles would be able to achieve the minimum performance requirement without adding additional hardware to their current AEB systems, a small percentage would need to add either an additional camera or radar. Based on the prevalence of mono-camera systems in our test data and in NCAP reporting data, as well as a discussion with Bosch, this analysis estimated that approximately five percent of new light vehicles would require additional hardware.[163] Therefore, in addition to software costs, the agency also accounts for the incremental cost for five percent of new light vehicles would add additional hardware (radar) to their existing AEB systems in order to meet the requirements specified in this final rule. Taking into account both software and hardware costs, the total annual

[163] Ex Parte Docket Memo and Presentation_ Bosch, available at: *https://www.regulations.gov/document/NHTSA-2023-0021-1058.*

cost associated with this final rule is approximately $354.06 million in 2020 dollars.

Table 26: Summary of Incremental Costs

Category	Percentage of New Light Vehicles Impacted	Total Annual Cost (Millions)
Software	100%	$282.20
Hardware	5%	$71.86
Total		**$354.06**

C. Net Impact

The Benefits associated with this final rule, which are measured in fatalities prevented and non-fatal injuries reduced, were converted into equivalent lives saved. Under this final rule, the cost per equivalent life saved ranges from $0.55 million and $0.68 million. Therefore, the final rule is considered to be cost-effective. To calculate net benefits, both measures must be represented in commeasurable units. Therefore, total benefits are translated into monetary value. When discounted at three and seven percent, the net benefits associated with the final rule are $7.26 billion and $5.82 billion, respectively. Furthermore, when discounted at three and seven percent, the benefit cost ratios associated with the final rule are 21.51 and 17.45, respectively. Therefore, this final rule is net beneficial. Overall, the agency's analyses indicate that society will be better off as a result of the final rule.

Table 27: Calculation of Monetized Benefits

MAIS Level	Non-Fatal Injuries and Fatalities Mitigated	Comprehensive Cost of Injuries	Monetized Benefits (Billions)
MAIS 1	20,538	$66,071	$1.36
MAIS 2	2,976	$504,776	$1.50
MAIS 3	689	$2,172,806	$1.50
MAIS 4	94	$3,825,873	$0.36
MAIS 5	24	$6,414,626	$0.15
Fatal	362	$11,937,313	$4.32
Total			**$9.19**

Note: Values may not sum due to rounding.

Table 28: Discounted Monetized Benefits (Billions)

Monetized Benefits	Discount Rate		Discounted Monetized Benefits
$9.19	3%	0.8285	$7.61
	7%	0.6721	$6.18

Table 29: Summary of Net Benefits (Millions)

Total Cost	Monetized Benefits		Net Benefits	
	3%	7%	3%	7%
$354.06	$7,614.86	$6,177.36	$7,260.80	$5,823.31

V. Regulatory Notices and Analyses

Executive Orders 12866, 13563, and 14094 and DOT Regulatory Policies and Procedures

The agency has considered the impact of this rulemaking action under Executive Order (E.O.) 12866, E.O. 13563, E.O. 14094, and the Department of Transportation's regulatory procedures. This rulemaking is considered ''(3)(f)(1) significant'' and was reviewed by the Office of Management and Budget under E.O. 12866, ''Regulatory Planning and Review,'' as amended by E.O. 14094, ''Modernizing Regulatory Review.'' It is expected to have an annual effect on the economy of $200 million or more. NHTSA has prepared a regulatory impact analysis that assesses the cost and benefits of this rule, which has been included in the docket listed at the beginning of this rule. The benefits, costs, and other impacts of this rule are summarized in the final regulatory impact analysis.

Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980, as amended, requires agencies to evaluate the potential effects of their proposed and final rules on small businesses, small organizations, and small governmental jurisdictions. The Small Business Administration's regulations at 13 CFR part 121 define a small business, in part, as a business entity ''which operates primarily within the United States.'' (13 CFR 121.105(a)). No regulatory flexibility analysis is required if the head of an agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. The SBREFA amended the Regulatory Flexibility Act to require Federal agencies to provide a statement of the factual basis for certifying that a rule will not have a significant economic impact on a substantial number of small entities.

NHTSA has considered the effects of this final rule under the Regulatory Flexibility Act.

The RIA discusses the economic impact of the rule on small vehicle manufacturers, of which NHTSA is aware of 12. NHTSA believes that this rule would not have a significant economic impact on these manufacturers. The vehicles produced by manufacturers listed in RIA can roughly be grouped into three classes: (1) luxury/ultra-luxury vehicles; (2) alternative electric vehicles; and (3) modified vehicles from other manufacturers. For luxury/ultra-luxury vehicles, any potential incremental compliance costs would not impact demand. Similarly, we would expect alternative electric vehicles to offer amenities meeting or exceeding the established market alternatives, including effective AEB and PAEB systems. Lastly, regarding final stage manufacturers, NHTSA is aware that these manufacturers buy incomplete vehicles from first-stage manufacturers. Then these vehicles are modified from larger manufacturer stock that would already be compliant. Therefore, there would be no incremental compliance costs.

As noted in the NPRM, much of the work developing and manufacturing AEB system components would be conducted by suppliers. Although the final certification would be made by the manufacturer, the NPRM proposed allowing for one additional year for small-volume manufacturers to comply with any requirement. That approach is similar to the approach we have taken in other rulemakings in recognition of manufacturing differences between larger and smaller manufacturers. As the countermeasures are developed, AEB suppliers would likely supply larger vehicle manufacturers first, before small manufacturers. In the proposed rule, NHTSA recognized this and maintained the agency's position that small manufacturers need additional flexibility, so they have time to obtain the equipment and work with the suppliers after the demands of the larger manufacturers are met.

The difference between the proposal and what is finalized in this rule is that NHTSA is no longer pursuing different lead-times based on the technology or phase-in schedules. Rather, the agency is providing all manufacturers with two extra years of lead time for lead vehicle AEB and one extra year of lead time for the most stringent requirements for PAEB (*i.e.,* 5 years of lead time regardless of technology). The rule adopts a 5-year lead time for all requirements and all manufacturers to ensure that the public attains lead vehicle AEB and PAEB safety benefits as soon as practicable. Small volume manufacturers would not have to comply for six years due to the additional year provided to them.

This rule may also affect final stage manufacturers, many of whom would be small businesses. While it is NHTSA's understanding that final stage manufacturers rarely make modifications to a vehicle's braking system and instead rely upon the pass-through certification provided by a first-stage manufacturers, as with small-volume manufacturers, final stage manufacturers would be provided with one additional year to comply with any requirement.

NHTSA received comments on the Regulatory Flexibility Act analysis included in the NPRM. One commenter asserted that NHTSA did not adequately consider the additional burden for small volume manufacturers and the unique design characteristics that would present additional compliance challenges for small manufacturers. The unique design considerations include low ground clearance, bumper characteristics that would require mounting radar very close to the ground, thereby requiring additional engineering to manage increased sensor signal noise, the general shape of the bumper, and the materials used for the bumper. This commenter said that the combination of these factors raises the risk of false positives and/or angular distortion of the target object in vertical and horizontal plane. Another commenter raised concerns about the engineering challenges faced by manufacturers of ''SuperCars'' and concern that these manufacturers would revert to seeking exemptions instead of pursuing FMVSS compliance.

In response to these comments, NHTSA notes that it has extended the lead time for all manufacturers to 5 years in this final rule. As proposed, final stage manufacturers and small-volume manufacturers would receive an additional year to comply, thus giving those entities 6 years to comply with this final rule. NHTSA believes that 6 years is sufficient time for even the smallest manufacturers to design and conform their products to this FMVSS, or seek an exemption if they have grounds under one of the bases listed in 49 CFR part 555.

I certify that this final rule would not have a significant economic impact on a substantial number of small entities. Additional information concerning the potential impacts of this rule on small entities is presented in the RIA accompanying this rule.

National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA) [164] requires Federal agencies to analyze the environmental impacts of proposed major Federal actions significantly affecting the quality of the human environment, as well as the impacts of alternatives to the proposed action.[165] The Council on Environmental Quality (CEQ) directs Federal agencies to prepare an environmental assessment for a proposed action ''that is not likely to

[164] 42 U.S.C. 4321–4347.

[165] 42 U.S.C. 4332(2)(C).

have significant effects or when the significance of the effects is unknown.'' [166] When a Federal agency prepares an environmental assessment, CEQ's NEPA implementing regulations require it to (1) ''[b]riefly provide sufficient evidence and analysis for determining whether to prepare an environmental impact statement or a finding of no significant impact;'' and (2) ''[b]riefly discuss the purpose and need for the proposed action, alternatives . . ., and the environmental impacts of the proposed action and alternatives, and include a listing of agencies and persons consulted.'' [167]

This section serves as NHTSA's Final Environmental Assessment (EA). In this Final EA, NHTSA outlines the purpose and need for the rulemaking, a reasonable range of alternative actions the agency considered through rulemaking, the projected environmental impacts of these alternatives. NHTSA did not receive any comments on the Draft EA.

Purpose and Need

This final rule sets forth the purpose of and need for this action. In this final rule, NHTSA is adopting a new FMVSS to require AEB systems on light vehicles capable of reducing the frequency and severity of both lead vehicle rear-end (lead vehicle AEB) and pedestrian crashes (PAEB). As explained earlier in this preamble, the AEB system improves safety by using various sensor technologies and sub-systems that work together to detect when the vehicle is in a crash imminent situation, to automatically apply the vehicle brakes if the driver has not done so, or to apply more braking force to supplement the driver's braking, thereby detecting and reacting to an imminent crash with a lead vehicle or pedestrian. This final rule promotes NHTSA's goal to reduce the frequency and severity of crashes described in the summary of the crash problem discussed earlier in the final rule, and advances DOT's January 2022 National Roadway Safety Strategy that identified requiring AEB, including PAEB technologies, on new passenger vehicles as a key Departmental action to enable safer vehicles. This final rule also responds to a mandate under the Bipartisan Infrastructure Law (BIL) directing the Department to promulgate such a rule.

Alternatives

NHTSA considered four regulatory alternatives for the proposed action and a ''no action alternative.'' Under the no action alternative, NHTSA would not issue a final rule requiring that vehicles be equipped with systems that meet minimum specified performance requirements, and manufacturers would continue to add AEB systems voluntarily. However, because the BIL directs NHTSA to promulgate a rule that would require that all passenger vehicles be equipped with an AEB system, NHTSA cannot adopt the no action alternative. Alternative 1 considers requirements specific to lead vehicle AEB only. Alternative 2 includes the lead vehicle AEB requirements in Alternative 1 and a requirement in which PAEB is only required to function in daylight conditions. Alternative 3, the selected alternative, considers requirements for lead vehicle AEBs and PAEB requirements in both daylight and darkness conditions. Alternative 4 considers a more-stringent requirement in which PAEB would be required to provide pedestrian protections in turning scenarios (no change to the lead vehicle AEB requirements in the final rule).

NHTSA also considered other options, including the International Organization for Standardization (ISO) standards, SAE International standards, the Economic Commission for Europe (ECE) standards, test procedures used by NHTSA's New Car Assessment Program (NCAP) and Euro NCAP, which are described above in this preamble and accompanying appendices. In the final rule, NHTSA incorporates aspects of the test procedures and standards mentioned here, but departs from them in numerous and significant ways.

Environmental Impacts of the Proposed Action and Alternatives

This final rule is anticipated to result in the employment of sensor technologies and sub-systems on light vehicles that work together to sense when a vehicle is in a crash imminent situation, to automatically apply the vehicle brakes if the driver has not done so, and to apply more braking force to supplement the driver's braking if insufficient. This final rule is also anticipated to improve safety by mitigating the number of fatalities, non-fatal injuries, and property damage that would result from crashes that could potentially be prevented or mitigated because of AEB. As a result, the primary environmental impacts [168] that could potentially result from this rulemaking are associated with: greenhouse gas emissions and air quality, socioeconomics, public health and safety, solid waste/property damage/congestion, and hazardous materials. Consistent with CEQ regulations and guidance, this EA discusses impacts in proportion to their potential significance. The effects of the final rule that were analyzed further are summarized below.

Greenhouse Gas Emissions and Air Quality

NHTSA has previously recognized that additional weight required by FMVSS could potentially negatively impact the amount of fuel consumed by a vehicle, and accordingly result in greenhouse gas emissions or air quality impacts from criteria pollutant emissions. Atmospheric greenhouse gases (GHGs) affect Earth's surface temperature by absorbing solar radiation that would otherwise be reflected back into space. Carbon dioxide (CO_2) is the most significant greenhouse gas resulting from human activity. Motor vehicles emit CO_2 as well as other GHGs, including methane and nitrous oxides, in addition to criteria pollutant emissions that negatively affect public health and welfare.

Additional weight added to a vehicle, like added hardware from safety systems, can cause an increase in vehicle fuel consumption and emissions. An AEB system requires the following hardware: sensing, perception, warning hardware, and electronically modulated braking subsystems.[169] As discussed in the preamble and the RIA, NHTSA anticipates that under the no action alternative and Alternatives 1–3, the majority of vehicles subject to the rulemaking would already have all of the hardware capable of meeting the requirements by the effective date of a final rule. For all alternatives, NHTSA assumes that manufacturers will need

[166] 40 CFR 1501.5(a).

[167] 40 CFR 1501.5(c).

[168] NHTSA anticipates that this rulemaking would have negligible or no impact on the following resources and impact categories, and therefore has not analyzed them further: topography, geology, soils, water resources (including wetlands and floodplains), biological resources, resources protected under the Endangered Species Act, historical and archeological resources, farmland resources, environmental justice, and section 4(f) properties.

[169] Automatic actuation of a vehicle's brakes requires more than just technology to sense when a collision is imminent. In addition to the sensing system, hardware is needed to apply the brakes without relying on the driver to depress the brake pedal. The automatic braking system relies on two foundational braking technologies—electronic stability control to automatically activate the vehicle brakes and an antilock braking system to mitigate wheel lockup. Not only do electronic stability control and antilock braking systems enable AEB operation, these systems also modulate the braking force so that the vehicle remains stable while braking during critical driving situations where a crash with a vehicle or pedestrian is imminent.

time to build code that analyses the frontal view of the vehicle (*i.e.,* manufacturers would need to upgrade the software for the perception subsystem) in a way that achieves the requirements of this final rule. Furthermore, approximately five percent of vehicles would add additional hardware such as a camera or radar. In addition to those costs, Alternative 4 includes an assumption that two cameras would be added; however, based on weight assumptions included in studies cited in the RIA, that weight impact would be minimal. The incremental weight associated with a stereo camera module is 785 g (1.73 lbs.) and for the entire camera and radar fused system is 883 g. (1.95 lbs.). NHTSA has previously estimated that a 3–4-pound increase in vehicle weight is projected to reduce fuel economy by 0.01 mpg.[170] Accordingly, Alternatives 1–3 would not have any fuel economy penalty for 95 percent of vehicles subject to the rulemaking because no hardware would be added. The potential impact on fuel economy for those five percent that would add an additional hardware would be negligible as it would potentially be under a pound when considering half the weight of either the stereo camera module or camera and radar fused system or under two pounds based on the stereo camera module. Similarly, Alternative 4 would potentially have a negligible fuel economy penalty as the potential incremental weight would be under two pounds based on the stereo camera module.

Pursuant to the Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) has established a set of National Ambient Air Quality Standards (NAAQS) for the following ''criteria'' pollutants: carbon monoxide (CO), nitrogen dioxide (NO_2), ozone, particulate matter (PM) less than 10 micrometers in diameter (PM_{10}), PM less than 2.5 micrometers in diameter ($PM_{2.5}$), sulfur dioxide (SO_2), and lead (Pb). The NAAQS include ''primary'' standards and ''secondary'' standards. Primary standards are intended to protect public health with an adequate margin of safety. Secondary standards are set at levels designed to protect public welfare by accounting for the effects of air pollution on vegetation, soil, materials, visibility, and other aspects of the general welfare. Under the General Conformity Rule of the CAA,[171] EPA requires a conformity determination when a Federal action would result in total direct and indirect emissions of a criteria pollutant or precursor originating in nonattainment or maintenance areas equaling or exceeding the emissions thresholds specified in 40 CFR 93.153(b)(1) and (2). The General Conformity Rule does not, however, require a conformity determination for Federal ''rulemaking and policy development and issuance,'' such as this action.[172] Therefore, NHTSA has determined it is not required to perform a conformity analysis for this action.

Socioeconomics

The socioeconomic impacts of the rulemaking would be primarily felt by vehicle manufacturers, light vehicle drivers, passengers, and pedestrians on the road that would otherwise be killed or injured in light vehicle crashes. NHTSA conducted a detailed assessment of the economic costs and benefits of establishing the new rule in its RIA. The main economic benefits come primarily from the reduction in fatalities and non-fatal injuries (safety benefits). Reductions in the severity of motor vehicle crashes would be anticipated to have corresponding reductions in costs for medical care, emergency services, insurance administrative costs, workplace costs, and legal costs due to the fatalities and injuries avoided. Other socioeconomic factors discussed in the RIA that would affect these parties include software and some hardware costs and property damage savings. Overall, Alternative 1 is anticipated to have societal net benefits of $3.40 to $4.28 billion, Alternative 2 is anticipated to have societal net benefits of $4.23 to $5.30 billion, Alternative 3 (the selected alternative) is anticipated to have societal net benefits of $5.82 to $7.26 billion, and Alternative 4 is anticipated to have societal net benefits of $4.18 to $5.73 billion. The RIA discusses this information in further detail.

Public Health and Safety

The affected environment for public health and safety includes roads, highways and other driving locations used by all light vehicle drivers, other drivers, passengers in light vehicles and other motor vehicles, and pedestrians or other individuals who could be injured or killed in crashes involving the vehicles regulated by the proposed action. In the RIA, the agency determined the impacts on public health and safety by estimating the reduction in fatalities and injuries resulting from the decreased crash severity due to the use of AEB systems under the four action alternatives. Under Alternative 1, it is expected that the addition of a less stringent requirement that only specifies requirements for lead vehicle AEB would result each year in 314 to 388 equivalent lives saved. Under Alternative 2, it is expected that the less-stringent requirement, in which PAEB is only required to function in daylight conditions, would result each year in 384 to 473 equivalent lives saved. Under Alternative 3 (the selected alternative), it is expected that the regulatory option would result each year in 517 to 638 equivalent lives saved. Finally, under Alternative 4, it is expected that the addition of more stringent requirements in which PAEB would be required to provide pedestrian protections in turning scenarios would result each year in 555 to 684 equivalent lives saved. The RIA discusses this information in further detail.

Solid Waste/Property Damage/ Congestion

Vehicle crashes can generate solid wastes and release hazardous materials into the environment. The chassis and engines, as well as associated fluids and components of automobiles and the contents of the vehicles, can all be deemed waste and/or hazardous materials. Solid waste can also include damage to the roadway infrastructure, including road surface, barriers, bridges, and signage. Hazardous materials are substances that may pose a threat to public safety or the environment because of their physical, chemical, or radioactive properties when they are released into the environment, in this case as a result of a crash.

NHTSA's rulemaking is projected to reduce the amount and severity of light vehicle crashes, and therefore may reduce the quantity of solid waste, hazardous materials, and other property damage generated by light vehicle crashes in the United States. The addition of an AEB system may also result in reduced damage to the vehicles and property, as well as reduced travel delay costs due to congestion. This is especially the case in ''property-damage-only'' crashes, where no individuals are injured or killed in the crash, but there may be damage to the vehicle or whatever is impacted by it. NHTSA estimates that based off data from 2016–2019 alone, an average of 1.12 million rear-impact crashes involving light vehicles occurred

[170] Final Regulatory Impact Analysis, Corporate Average Fuel Economy for MYs 2012–2016 Passenger Cars and Light Trucks, Table IV–5 (March 2010).

[171] Section 176(c) of the CAA, codified at 42 U.S.C. 7506(c); To implement CAA section 176(c), EPA issued the General Conformity Rule (40 CFR part 51, subpart W and part 93, subpart B).

[172] 40 CFR 93.153(c)(2)(iii).

annually. These crashes resulted in an annual average of 394 fatalities, 142,611 non-fatal injuries, and approximately 1.69 million PDOVs.

Less solid waste translates into cost and environmental savings from reductions in the following areas: (1) transport of waste material, (2) energy required for recycling efforts, and (3) landfill or incinerator fees. Less waste will result in beneficial environmental effects through less GHG emissions used in the transport of it to a landfill, less energy used to recycle the waste, less emissions through the incineration of waste, and less point source pollution at the scene of the crash that would result in increased emissions levels or increased toxins leaking from the crashed vehicles into the surrounding environment.

The addition of an AEB system may also result in reduced post-crash environmental effects from congestion. As discussed in the RIA, NHTSA's monetized benefits are calculated by multiplying the number of non-fatal injuries and fatalities mitigated by their corresponding ''comprehensive costs.'' The comprehensive costs include economic costs that are external to the value of a statistical life (VSL) costs, such as emergency management services or legal costs, and congestion costs. NHTSA has recognized that motor vehicle crashes result in congestion that has both socioeconomic and environmental effects. These environmental effects include ''wasted fuel, increased greenhouse gas production, and increased pollution as engines idle while drivers are caught in traffic jams and slowdowns.'' [173] NHTSA's monetized benefits therefore include a quantified measure of congestion avoidance. NHTSA did not calculate congestion effects specifically for each regulatory alternative; however, because comprehensive costs are a discrete cost applied to non-fatal injuries and fatalities at the same rate, we can conclude that there are increasing benefits associated with fewer crashes, and specifically decreased congestion, as the monetized benefits increase across regulatory alternatives. To the extent that any regulatory option for AEB results in fewer crashes and accordingly higher monetized benefits, there would be fewer congestion-related environmental effects.

NHTSA has tentatively concluded that under the agency's rulemaking, the economic benefits resulting from improved safety outcomes, property damage savings, fuel savings, and GHG reductions would limit the negative environmental impacts caused by additional solid waste/property damage due to crashes because of the crashes that will be avoided due to the requirements of this rule. Similarly, while the potential degree of hazardous materials spills prevented due to the reduction of crash severity and crash avoidance expected from the rulemaking has not specifically been analyzed in the RIA or final rule, the addition of the AEB system is projected to reduce the amount and severity of light vehicle crashes and may improve the environmental effects with respect to hazardous material spills. While the RIA does not specifically quantify these impact categories, in general NHTSA believes the benefits would increase relative to the crashes avoided and would be relative across the different alternatives. The RIA discusses information related to quantified costs and benefits of crashes, and in particular property damage due to crashes, for each regulatory alternative in further detail.

Cumulative Impacts

In addition to direct and indirect effects, CEQ regulations require agencies to consider cumulative impacts of major Federal actions. CEQ regulations define cumulative impacts as the impact ''on the environment that result from the incremental [impact] of the action when added to . . . other past, present, and reasonably foreseeable actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions.'' [174] NHTSA notes that the public health and safety, solid waste/property damage/congestion, air quality and greenhouse gas emissions, socioeconomic, and hazardous material benefits identified in this EA were based on calculations described in the RIA, in addition to other NHTSA actions and studies on motor vehicle safety as described in the preamble. That methodology required the agency to adjust historical figures to reflect vehicle safety rulemakings that have recently become effective. As a result, many of the calculations in this EA already reflect the incremental impact of this action when added to other past actions.

NHTSA's and other parties' past actions that improve the safety of light vehicles, as well as future actions taken by the agency or other parties that improve the safety of light vehicles, could further reduce the severity or number of crashes involving light vehicles. Any such cumulative improvement in the safety of light vehicles would have an additional effect in reducing injuries and fatalities and could reduce the quantity of solid and hazardous materials generated by crashes. To the extent that this rule may have some minimal impact on fuel economy for the small percentage of vehicles where additional hardware may be required, NHTSA would consider that impact when setting maximum feasible fuel economy standards.'' [175]

Agencies and Persons Consulted

This preamble describes the various materials, persons, and agencies consulted in the development of the final rule. NHTSA invited public comments on the contents and tentative conclusions of the Draft EA. No public comments addressing the Draft EA were received. Furthermore, none of the public comments that were received addressed any issues related to the human environment that would be relevant to the Final EA.

Finding of No Significant Impact

Although this rule is anticipated to result in additional FMVSS requirements for light vehicle manufacturers, AEB systems have already largely been introduced by manufacturers voluntarily. The addition of regulatory requirements (depending on the regulatory alternative) to standardize the AEB systems in all vehicle models is anticipated to result in negligible or no fuel economy and emissions penalties (*i.e.,* five percent of vehicles would require additional hardware, but the added weight is negligible), increasing socioeconomic and public safety benefits as the alternatives get more stringent, and an increase in benefits from the reduction in solid waste, property damage, and congestion (including associated traffic level impacts like reduction in energy consumption and tailpipe pollutant emissions) from fewer vehicle crashes across the regulatory alternatives.

Based on the Final EA, NHTSA concludes that implementation of any of the alternatives considered for the proposed action, including the selected alternative, will not have a significant effect on the human environment and that a ''finding of no significant impact''

[173] Blincoe, L.J., Miller, T.R., Zaloshnja, E., & Lawrence, B.A. (2015, May). The economic and societal impact of motor vehicle crashes, 2010. (Revised) (Report No. DOT HS 812 013). Washington, DC: National Highway Traffic Safety Administration.

[174] 40 CFR 1508.1(g)(3).

[175] 49 U.S.C. 32902(f), which states that we consider the effect of other motor vehicle standards of the Government on fuel economy in the max feasible discussion.

is appropriate. This statement constitutes the agency's ''finding of no significant impact,'' and an environmental impact statement will not be prepared.[176]

Executive Order 13132 (Federalism)

NHTSA has examined this rule pursuant to Executive Order 13132 (64 FR 43255, August 10, 1999) and concluded that no additional consultation with States, local governments, or their representatives is mandated beyond the rulemaking process. The agency has concluded that this rule will not have sufficient federalism implications to warrant consultation with State and local officials or the preparation of a federalism summary impact statement. The rule does not have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

NHTSA rules can preempt in two ways. First, the National Traffic and Motor Vehicle Safety Act contains an express preemption provision: When a motor vehicle safety standard is in effect under this chapter, a State or a political subdivision of a State may prescribe or continue in effect a standard applicable to the same aspect of performance of a motor vehicle or motor vehicle equipment only if the standard is identical to the standard prescribed under this chapter. 49 U.S.C. 30103(b)(1). It is this statutory command by Congress that preempts any non-identical State legislative and administrative law addressing the same aspect of performance. The express preemption provision described above is subject to a savings clause under which compliance with a motor vehicle safety standard prescribed under this chapter does not exempt a person from liability at common law. 49 U.S.C. 30103(e). Pursuant to this provision, State common law tort causes of action against motor vehicle manufacturers that might otherwise be preempted by the express preemption provision are generally preserved. However, the Supreme Court has recognized the possibility, in some instances, of implied preemption of such State common law tort causes of action by virtue of NHTSA's rules, even if not expressly preempted. The second way that NHTSA rules can preempt is dependent upon there being an actual conflict between an FMVSS and the higher standard that would effectively be imposed on motor vehicle manufacturers if someone obtained a State common law tort judgment against the manufacturer, notwithstanding the manufacturer's compliance with the NHTSA standard. Because most NHTSA standards established by an FMVSS are minimum standards, a State common law tort cause of action that seeks to impose a higher standard on motor vehicle manufacturers will generally not be preempted. If and when such a conflict does exist—for example, when the standard at issue is both a minimum and a maximum standard—the State common law tort cause of action is impliedly preempted. *See Geier* v. *American Honda Motor Co.,* 529 U.S. 861 (2000).

Pursuant to Executive Orders 13132 and 12988, NHTSA has considered whether this rule could or should preempt State common law causes of action. The agency's ability to announce its conclusion regarding the preemptive effect of one of its rules reduces the likelihood that preemption will be an issue in any subsequent tort litigation. To this end, the agency has examined the nature (*i.e.,* the language and structure of the regulatory text) and objectives of this rule and finds that this rule, like many NHTSA rules, would prescribe only a minimum safety standard. As such, NHTSA does not intend this rule to preempt state tort law that would effectively impose a higher standard on motor vehicle manufacturers. Establishment of a higher standard by means of State tort law will not conflict with the minimum standard adopted here. Without any conflict, there could not be any implied preemption of a State common law tort cause of action.

Executive Order 12988 (Civil Justice Reform)

When promulgating a regulation, section 3(b) of Executive Order 12988, ''Civil Justice Reform'' (61 FR 4729, February 7, 1996) requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect; (2) clearly specifies the effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct, while promoting simplification and burden reduction; (4) clearly specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. This document is consistent with that requirement.

Pursuant to this Order, NHTSA notes that the preemptive effect of this rulemaking is discussed above in connection with Executive Order 13132. NHTSA notes further that there is no requirement that individuals submit a petition for reconsideration or pursue other administrative proceeding before they may file suit in court.

Executive Order 13045 (Protection of Children From Environmental Health and Safety Risks)

Executive Order 13045, ''Protection of Children from Environmental Health and Safety Risks,'' (62 FR 19885; April 23, 1997) applies to any proposed or final rule that: (1) Is determined to be ''economically significant,'' as defined in E.O. 12866, and (2) concerns an environmental health or safety risk that NHTSA has reason to believe may have a disproportionate effect on children. If a rule meets both criteria, the agency must evaluate the environmental health or safety effects of the rule on children, and explain why the rule is preferable to other potentially effective and reasonably feasible alternatives considered by the agency.

This rule is not expected to have a disproportionate health or safety impact on children. Consequently, no further analysis is required under Executive Order 13045.

Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et. seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. NHTSA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. Because this rule meets the criteria in 5 U.S.C. 804(2), it will be effective sixty days after the date of publication in the **Federal Register**.

Paperwork Reduction Act (PRA)

Under the PRA of 1995, a person is not required to respond to a collection of information by a Federal agency unless the collection displays a valid OMB control number. There are no ''collections of information'' (as defined at 5 CFR 1320.3(c)) in this rule.

[176] 40 CFR 1501.6(a).

National Technology Transfer and Advancement Act

Under the National Technology Transfer and Advancement Act of 1995 (NTTAA) (Pub. L. 104–113), all Federal agencies and departments shall use technical standards developed or adopted by voluntary consensus standards bodies, using such technical standards as a means to carry out policy objectives or activities determined by the agencies and departments. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) developed or adopted by voluntary consensus standards bodies, such as the International Organization for Standardization and SAE International. The NTTAA directs us to provide Congress, through OMB, explanations when we decide not to use available and applicable voluntary consensus standards.

NHTSA is incorporating by reference ISO and ASTM standards into this rule. NHTSA considered several ISO standards and has opted to use ISO 19206–3:2021 to specify the vehicle test device and a combination of ISO 19206–2:2018 and ISO 19206–4:2020 to specify the test mannequins. NHTSA is incorporating by reference ASTM E1337–19, which is already incorporated by reference into many FMVSSs, to measure the peak braking coefficient of the testing surface.

NHTSA considered SAE International Recommended Practice J3087, ''Automatic emergency braking (AEB) system performance testing,'' which defines the conditions for testing AEB and FCW systems. This standard defines test conditions, test targets, test scenarios, and measurement methods, but does not provide performance criteria. There is considerable overlap in the test setup and conditions between this rule and the SAE standard including the basic scenarios of lead vehicle stopped, slower moving, and decelerating. This SAE recommended practice is substantially similar to the existing NCAP test procedures and this rule.

NHTSA also considered SAE International Standard J3116, ''Active Safety Pedestrian Test Mannequin Recommendation,'' which provides recommendations for the characteristics of a surrogate that could be used in testing of active pedestrian safety systems. As proposed, NHTSA incorporates the ISO standard because the ISO standard specifications are more widely adopted than the SAE Recommended Practice.

In appendix B of the NPRM's preamble, NHTSA described several international test procedures and regulations the agency considered for use in this rule. This rule has substantial technical overlap with UNECE Regulation No. 131 and UNECE Regulation No. 152. This rule and the UNECE regulations both specify a forward collision warning and automatic emergency braking. Several lead vehicle AEB scenarios are nearly identical, including the lead vehicle stopped and lead vehicle moving scenarios. The pedestrian crossing path scenario specified in UNECE Regulation No. 152 is also substantially similar to this rule. As discussed in the preamble, this rule differs from the UNECE standards in the areas of maximum test speed and the minimum level of required performance. This rule uses higher test speeds and a requirement that the test vehicle avoid contact, both of which are more stringent than the UNECE regulations and more reflective of the safety need in the United States. NHTSA expects that this approach would increase the repeatability of the test and maximize the realized safety benefits of the rule.

Incorporation by Reference

Under regulations issued by the Office of the Federal Register (1 CFR 51.5), an agency, as part of a proposed rule that includes material incorporated by reference, must summarize material that is proposed to be incorporated by reference and discuss the ways the material is reasonably available to interested parties or how the agency worked to make materials available to interested parties. At the final rule stage, regulations require that the agency seek formal approval, summarize the material that it incorporates by reference in the preamble of the final rule, discuss the ways that the materials are reasonably available to interested parties, and provide other specific information to the Office of the Federal Register.

In this rule, NHTSA incorporates by reference six documents into the Code of Federal Regulations, ASTM E1337–19, *Standard Test Method for Determining Longitudinal Peak Braking Coefficient (PBC) of Paved Surfaces Using Standard Reference Test Tire,* is already incorporated by reference elsewhere in 49 CFR part 571. ASTM E1337 is a standard test method for evaluating peak braking coefficient of a test surface using a standard reference test tire using a trailer towed by a vehicle. NHTSA uses this method in all of its braking and electronic stability control standards to evaluate the test surfaces for conducting compliance test procedures.

NHTSA also incorporates by reference SAE J2400 *Human Factors in Forward Collision Warning System: Operating Characteristics and User Interface Requirements,* into part 571. SAE J2400 is an information report intended as a starting point of reference for designers of forward collision warning systems. NHTSA incorporates this document by reference solely to specify the location specification and symbol for a visual forward collision warning.

NHTSA incorporates by reference four ISO standards into 49 CFR part 596. The first of these standards is ISO 3668:2017(E), *Paints and varnishes—Visual comparison of colour of paints.* This document specifies a method for the visual comparison of the color of paints against a standard. This method will be used to verify the color of certain elements of the pedestrian test mannequin NHTSA will use in PAEB testing. Specifically, NHTSA will use these procedures to determine that the color of the hair, torso, arms, and feet of the pedestrian test mannequin is black and that the color of the legs are blue.

NHTSA incorporates by reference ISO 19206–2:2018(E), *Road vehicles—Test devices for target vehicles, vulnerable road users and other objects, for assessment of active safety functions—Part 2: Requirements for pedestrian targets.* This document addresses the specification for a test mannequin. It is designed to resemble the characteristics of a human, while ensuring the safety of the test operators and preventing damage to subject vehicles in the event of a collision during testing. NHTSA references many, but not all, of the specifications of ISO 19206–2:2018, as discussed earlier in the preamble of this rule.

NHTSA also incorporates by reference ISO 19206–3:2021(E), *Test devices for target vehicles, vulnerable road users and other objects, for assessment of active safety functions—Part 3: Requirements for passenger vehicle 3D targets.* This document provides specification of three-dimensional test devices that resemble real vehicles. Like the test mannequin described in the prior paragraph, it is designed to ensure the safety of the test operators and to prevent damage to subject vehicles in the event of a collision during testing. NHTSA references many, but not all, of the specifications of ISO 19206–3:2021, as discussed earlier in the preamble of this rule.

Finally, NHTSA incorporates by reference ISO 19206–4:2020(E), *Road vehicles—test devices for target vehicles,*

vulnerable road users and other objects, for assessment of active safety functions—Part 4: Requirements for bicyclists targets. This standard describes specifications for bicycle test devices representative of adult and child sizes. NHTSA will not use a bicycle test device during testing for this final rule. Rather, this standard is incorporated by reference solely because it contains specifications for color and reflectivity, including skin color, that NHTSA is applying to its pedestrian test mannequin.

All standards incorporated by reference in this rule are available for review at NHTSA's headquarters in Washington, DC, and for purchase from the organizations promulgating the standards (see 49 CFR 517.5 for contact information). The ASTM standard presently incorporated by reference into other NHTSA regulations is also available for review at ASTM's online reading room.[177]

Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4) requires agencies to prepare a written assessment of the costs, benefits, and other effects of proposed or final rules that include a Federal mandate likely to result in the expenditures by States, local or tribal governments, in the aggregate, or by the private sector, of more than $100 million annually (adjusted annually for inflation with base year of 1995). Adjusting this amount by the implicit gross domestic product price deflator for 2021 results in an estimated current value of $165 million (2021 index value of 113.07/1995 index value of 68.60 = 1.65). The assessment may be included in conjunction with other assessments, as it is for this rule in the RIA.

A rule on lead vehicle AEB and PAEB is not likely to result in expenditures by State, local or tribal governments of more than $100 million annually. However, it is estimated to result in the estimated expenditure by automobile manufacturers and/or their suppliers of $354 million annually (estimated to be an average of approximately $23 per light vehicle annually). This average estimated cost impacts reflects that the estimated incremental costs depend on a variety of lead vehicle AEB hardware and software that manufacturers plan to install (in vehicles used as ''baseline'' for the cost estimate). The final cost will greatly depend on choices made by the automobile manufacturers to meet the lead vehicle AEB and PAEB test requirements. These effects have been discussed in the RIA developed in support of this final rule.

The Unfunded Mandates Reform Act requires the agency to select the ''least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule.'' As an alternative, the agency considered a full-vehicle dynamic test to evaluate the capability of lead vehicle AEB and PAEB systems to prevent crashes or mitigate the severity of crashes. Based on our experience on conducting vehicle tests for vehicles equipped with lead vehicle AEB and PAEB where we utilize a reusable surrogate target crash vehicle and test mannequins instead of conducting the test with an actual vehicle as the target, we determined that full vehicle-to-vehicle crash tests can have an undesired amount of variability in vehicle kinematics. Unlike vehicle-to-vehicle tests, the lead vehicle AEB and PAEB tests with a surrogate target vehicle is conducted in a well-controlled test environment, which results in an acceptable amount of variability. In addition, the agency's lead vehicle AEB and PAEB tests with surrogate target vehicle and pedestrian were able to reveal deficiencies in the system that resulted in inadequate system capability in detecting and activating the brakes. Therefore, we concluded that a full vehicle-to-vehicle test would not achieve the objectives of the rule.

In addition, the agency evaluated data across a broad range of test scenarios in an effort to identify the maximum range of test speeds at which it is feasible for test vehicles to achieve a no-contact result. The range of feasible speeds for no contact identified in the review was specified as the mandated range in the rule. Thus, there are no alternative test procedures available that would improve the ability of manufacturers to achieve no-contact results. In turn, the agency concluded that lead vehicle AEB and PAEB systems designed to meet the no-contact requirement at speeds outside the ranges specified in the rule would not achieve the objectives of the rule.

Executive Order 13609 (Promoting International Regulatory Cooperation)

The policy statement in section 1 of E.O. 13609 states, in part, that the regulatory approaches taken by foreign governments may differ from those taken by U.S. regulatory agencies to address similar issues and that, in some cases, the differences between the regulatory approaches of U.S. agencies and those of their foreign counterparts might not be necessary and might impair the ability of American businesses to export and compete internationally. The E.O. states that, in meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation, and that international regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements. NHTSA requested public comment on the ''regulatory approaches taken by foreign governments'' concerning the subject matter of this rulemaking. NHTSA received many comments expressing that NHTSA should either align or adopt existing international regulations. As discussed above, while NHTSA has adopted aspects of these regulations, it has rejected others because of the stringency of the regulations due to the reasons discussed in further detail in various parts of the preamble and National Technology Transfer and Advancement Act section.

Severability

The issue of severability of FMVSSs is addressed in 49 CFR 571.9. It provides that if any FMVSS or its application to any person or circumstance is held invalid, the remainder of the part and the application of that standard to other persons or circumstances is unaffected. It expresses NHTSA's view that, even with invalidated portions or applications disregarded, remaining portions and applications can still function sensibly.

Regulation Identifier Number

The Department of Transportation assigns a regulation identifier number (RIN) to each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. You may use the RIN contained in the heading at the beginning of this document to find this action in the Unified Agenda.

VI. Appendices to the Preamble

A. Appendix A: Description of the Lead Vehicle AEB Test Procedures Stopped Lead Vehicle

Test Parameters

The stopped lead vehicle scenario consists of the vehicle traveling straight ahead, at a constant speed, approaching a stopped lead vehicle in its path. The vehicle must be able to avoid contact with the stopped lead vehicle. The testing is at any subject vehicle speed

[177] *https://www.astm.org/products-services/reading-room.html.*

between 10 km/h and 80 km/h with no manual brake application and between 70 km/h and 100 km/h with manual brake application.

Test Conduct Prior to FCW Onset

Prior to the start of a test, the lead vehicle is placed with its longitudinal centerline coincident to the intended travel path and with no specific limitations on how a subject vehicle may be driven prior to the test start. As long as the specified initialization procedure is executed, a subject vehicle may be driven under any conditions including any speed and direction, and on any road surface, for any elapsed time prior to reaching the point where a test trial begins. As the subject vehicle approaches the rear of the lead vehicle, beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs. Furthermore, beginning when the headway corresponds to L_0, the subject vehicle heading is maintained with minimal steering input such that the subject vehicle travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s. The purpose of these test tolerances is to assure test practicability and repeatability of results.

Test Conduct After FCW Onset

During each test, the subject vehicle accelerator pedal is released in response to the FCW. The procedure states that the accelerator pedal is released at any rate and is fully released within 500 milliseconds for subject vehicles tested without cruise control active. The accelerator release procedure ensures consistent release of the accelerator and assures test repeatability. The accelerator pedal release can be omitted from tests of vehicles with cruise control actively engaged because there is no driver input to the accelerator pedal in that case. The AEB performance requirements are the same for vehicles with and without cruise control engaged, and AEB systems must provide an equivalent level of crash avoidance or mitigation regardless of whether cruise control is active.

For testing without manual brake application, no manual brake application is made until one of the test completion criteria is satisfied. For tests that include manual brake application, the service brakes are applied at 1.0 ± 0.1 second after FCW.

Test Completion Criteria

Any test is complete when the subject vehicle comes to a complete stop without making contact with the lead vehicle or when the subject vehicle makes contact with the lead vehicle.

Slower-Moving Lead Vehicle

Test Parameters

The slower-moving lead vehicle scenario involves the subject vehicle traveling straight ahead at constant speed, approaching a lead vehicle traveling at a slower speed in the subject vehicle path. NHTSA will test at the same two subject vehicle speed ranges as the stopped lead vehicle scenario depending on the manual brake application. The lead vehicle speed is 20 km/h.

Test Conduct Prior to FCW Onset

Prior to the start of a test trial the lead vehicle is propelled forward in a manner such that the longitudinal center plane of the lead vehicle does not deviate laterally more than 0.3m from the intended travel path.

As the subject vehicle approaches the rear of the lead vehicle, beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs. Furthermore, beginning when the headway corresponds to L_0, the subject vehicle and lead heading are to be maintained with minimal steering input such that the subject vehicle travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s.

Test Conduct After FCW Onset

Similar to the stopped lead vehicle test, the subject vehicle accelerator pedal is released in response to the FCW. The procedure states that the accelerator pedal is released at any rate and is fully released within 500 milliseconds for subject vehicles tested without cruise control active. The accelerator pedal release can be omitted from tests of vehicles with cruise control actively engaged due to the lack of driver input to the accelerator pedal.

For testing without manual brake application, no manual brake application is made until one of the test completion criteria is satisfied. For testing with manual brake application, the service brake application occurs at 1.0 ± 0.1 second after FCW onset.

Test Completion Criteria

Any test run is complete when the subject vehicle speed is less than or equal to the lead vehicle speed without making contact with the lead vehicle or when the subject vehicle makes contact with the lead vehicle.

Decelerating Lead Vehicle

Test Parameters

The decelerating lead vehicle scenario is meant to assess the AEB performance when the subject vehicle and lead vehicle initially are travelling at the same constant speed in a straight path and the lead vehicle begins to decelerate. NHTSA tests under two basic setups for this scenario, one where both the subject vehicle and lead vehicle initial travel speed ($V_{SV} = V_{LV}$) is 50 km/h and another where both vehicles travel at 80 km/h. For both testing speeds, NHTSA tests with, and without, manual brake application, at any headway between 12 m and 40 m and at any lead vehicle deceleration between 0.3 g and 0.5 g.

Test Conduct Prior to Lead Vehicle Braking Onset

Up to 3 seconds prior to the start of a test trial there are no specific limitations on how a subject vehicle may be driven. Between 3 seconds prior and the lead vehicle braking onset, the lead vehicle is propelled forward in a manner such that the longitudinal center plane of the lead vehicle does not deviate laterally more than 0.3m from the intended travel path. During this same time interval, the subject vehicle follows the lead vehicle at the testing headway distance between 12 m and 40m. While the subject vehicle follows the lead vehicle from 3 seconds prior and lead vehicle brake onset, the subject vehicle and lead vehicle speeds are maintained within 1.6 km/h and their travel paths do not deviate more than 0.3 m laterally from the centerline of the lead vehicle. The speed is to be maintained with minimal and smooth accelerator pedal inputs and the and yaw rate of the subject vehicle may not exceed ±1.0 deg/s.

Test Conduct After Lead Vehicle Braking Onset

The lead vehicle is decelerated to a stop with a targeted average deceleration of any value between 0.3g and 0.5g. The targeted deceleration magnitude is to be achieved within 1.5 seconds of lead vehicle braking onset and maintained until 250 ms prior to coming to a stop. Similar to the lead vehicle tests, during each test trial, the subject vehicle accelerator pedal is released in response to the FCW and fully released within 500 milliseconds.

In the same manner as the slower lead vehicle tests, when testing without

manual brake application, no manual brake application is made until one of the test completion criteria is satisfied. For testing with manual brake application, the service brake application occurs at 1.0 ± 0.1 second after FCW onset.

Test Completion Criteria

Any test run is complete when the subject vehicle comes to a complete stop without making contact with the lead vehicle or when the subject vehicle makes contact with the lead vehicle, similarly to the stopped lead vehicle tests.

Headway Calculation

For the scenarios where the headway is not specified (stopped lead vehicle and slower lead vehicle) the headway (L_0), in meters, providing 5 seconds time to collision (*TTC*) is calculated. L_0 is determined with the following equation where V_{SV} is the speed of the subject vehicle in m/s and V_{LV} is the speed of the lead vehicle in m/s:

$L_0 = \mathrm{TTC}_0 \times (V_{SV} - V_{LV})$

$TTC_0 = 5.0$

Travel Path

The intended travel path is the target path for a given test scenario and is identified by the projection onto the road surface of the frontmost point of the subject vehicle located on its longitudinal, vertical center plane. The subject vehicle's actual travel path is recorded and compared to the intended path.

The intended subject vehicle travel path is coincident with the center of a test lane whenever there are two edge lines marking a lane on the test track surface. If there is only one lane line (either a single or double line) marked on the test track, the vehicle path will be parallel to it and offset by 1.8 m (6 ft) to one side (measured from the inside edge of the line).

Subject Vehicle (Manual) Brake Application Procedures

Subject vehicle brake application is performed through either displacement or hybrid feedback at the manufacturer's choosing. The subject vehicle brake application procedures are consistent with the manual brake applications defined in NHTSA's NCAP test procedures for DBS performance assessment. The procedure is to begin with the subject vehicle brake pedal in its natural resting position with no preload or position offset.

Displacement Feedback Procedure

For the displacement feedback procedure, the commanded brake pedal position is the brake pedal position that results in a mean deceleration of 0.4 g in the absence of AEB system activation. The mean deceleration is the deceleration over the time from the pedal achieving the commanded position to 250 ms before the vehicle comes to a stop. The pedal displacement controller depresses the pedal at a rate of 254 mm/s ±25.4 mm/s to the commanded brake pedal position. The standard allows for the pedal displacement controller to overshoot the commanded position by any amount up to 20 percent. In the event of an overshoot, it may be corrected within 100 ms. The achieved brake pedal position is any position within 10 percent of the commanded position from 100 ms after pedal displacement occurs and any overshoot is corrected.

Hybrid Brake Pedal Feedback Procedure

For the hybrid brake pedal feedback procedure, the commanded brake pedal application is the brake pedal position and a subsequent commanded brake pedal force that results in a mean deceleration of 0.4 g in the absence of AEB system activation. The hybrid brake pedal application procedure follows the displacement application procedure, but instead of maintaining the achieved brake pedal displacement, the controller starts to control the force applied to the brake pedal (100 ms after pedal displacement occurs and any overshoot is corrected). The hybrid controller applies a pedal force of at least 11.1 N and maintains the pedal force within 10 percent of the commanded brake pedal force from 350 ms after commended pedal displacement occurs and any overshoot is corrected, until test completion.

Force Feedback Procedure

For the force feedback procedure, the commanded brake pedal application is the brake pedal force that results in a mean deceleration of 0.4 g in the absence of AEB system activation. The mean deceleration is the deceleration over the time from when the commanded brake pedal force is first achieved to 250 ms before the vehicle comes to a stop. The force controller achieves the commanded brake pedal force within 250 ms. The application rate is unrestricted. The force controller may overshoot the commanded force by up to 20 percent. If such an overshoot occurs, it is corrected within 250 ms from when the commanded force is first achieved. The force controller applies a pedal force of at least 11.1 N from the onset of the brake application until the end of the test.

B. Appendix B: Description of the PAEB Test Procedures

Test Parameters

The PAEB performance tests require a vehicle to avoid a collision with a pedestrian test device by applying the brakes automatically under certain test-track scenarios during daylight and darkness (with lower beam and with upper beams activated). Similar to the lead vehicle AEB performance test requirements, NHTSA adopted a no-contact requirement as a performance metric. The test scenarios for PAEB evaluation fall into three groups of scenarios based on the actions of the pedestrian test device—crossing path, stationary and along path. For each test conducted under the testing scenarios, NHTSA adopted the following options within those testing scenarios: (1) pedestrian crossing (right or left) relative to an approaching subject vehicle, (2) subject vehicle overlap (25% or 50%), (3) pedestrian obstruction (Yes/No), and (4) pedestrian speed stationary, walking, or running(V_P). Further parameters when approaching a pedestrian are selected from a subject vehicle speed range (V_{SV}) and the lighting condition (daylight, lower beams or upper beams). As opposed to lead vehicle AEB track testing, manual brake application by the driver is not a parameter of the test scenarios for PAEB.

Similarly to the lead vehicle AEB testing, NHTSA specifies that the travel path in each of the test scenarios be straight. For PAEB testing, the intended travel path of the subject vehicle is a straight line originating at the location corresponding to a headway of L_0.

NHTSA specifies that if the road surface is marked with a single or double lane line, the intended travel path be parallel to, and 1.8 m from the inside of the closest line. If the road surface is marked with two lane lines bordering the lane, the intended travel path is centered between the two lines.

For each PAEB test run, the headway (L_0), in meters, between the front plane of the subject vehicle and a parallel contact plane on the pedestrian test mannequin providing 4.0 seconds time to collision (*TTC*) is calculated. L_0 is determined with the following equation where V_{SV} is the speed of the subject vehicle in m/s and V_{P-y} is the component of speed of the pedestrian test mannequin in m/s in the direction of the intended travel path:

$L_0 = \mathrm{TTC}_0 \times (V_{SV} - V_{P\text{-}y})$

$\mathrm{TTC}_0 = 4.0$

Overlap describes the location of the point on the front of the subject vehicle that would make contact with the

pedestrian test mannequin (PTM) if no braking occurred and is the percentage of the subject vehicle's overall width that the pedestrian test mannequin traverses. It identifies the point on the subject vehicle that would contact a test mannequin within the subject vehicle travel path if the subject vehicle were to maintain its speed without braking, and it is measured from the right or the left (depending on the side of the subject vehicle where the pedestrian test mannequin originates).

Pedestrian Crossing Path

Test Parameters—Unobstructed From the Right

The unobstructed crossing path from the right scenario consists of the subject vehicle traveling straight at a constant speed towards the adult PTM, which enters its travel path (perpendicular to the vehicle's travel path) from the right side of the vehicle. The subject vehicle must be able to avoid contact with the pedestrian test mannequin crossing its path. NHTSA specifies testing the unobstructed crossing path scenario from the right with a 25% and 50% overlap during daylight and a 50% overlap for darkness with independent tests with the lower and upper beams activated. The subject vehicle testing speed is any speed between 10 km/h and 60 km/h, while the PTM speed is 5km/h.

Pedestrian Test Mannequin—Unobstructed From the Right

An adult PTM is used for this scenario and NHTSA specifies that the PTM is to be secured to a moving apparatus so that it faces the direction of motion at 4.0 ± 0.1 m to the right of the subject vehicle's intended travel path. The PTM's leg articulation is to start on apparatus movement and stops when the apparatus stops. The PTM speed is 5 km/h.

Test Parameters—Unobstructed From the Left

The unobstructed crossing path from the left scenario consists of the subject vehicle traveling straight at a constant speed towards the adult PTM, which enters its travel path (perpendicular to the vehicle's travel path) from the left side of the vehicle. The subject vehicle must be able to avoid contact with the pedestrian test mannequin crossing its path. NHTSA will test the unobstructed crossing path scenario from the left with a 50% overlap during daylight. The subject vehicle testing speed is any speed between 10 km/h and 60 km/h, while the PTM speed is 8 km/h.

Pedestrian Test Mannequin—Unobstructed From the Left

An adult PTM is used for this scenario, and NHTSA specifies that the PTM be secured to a moving apparatus so that it faces the direction of motion at 6.0 ± 0.1 m to the left of the intended travel path. The PTM's leg articulation is to start on apparatus movement and stops when the apparatus stops. As this simulates a running adult pedestrian, the PTM speed is 8 km/h.

Test Parameters—Obstructed From the Right

The obstructed crossing path from the right scenario consists of the subject vehicle traveling straight at a constant speed towards a child PTM, which enters its travel path (perpendicular to the travel path) from the right side of the vehicle. The child PTM crosses the subject vehicle's travel path from in front of two stopped VTDs. The VTDs are parked to the right of the subject vehicle's travel path, in the adjacent lane, at 1.0 m (3 ft) from the side of the subject vehicle (tangent with the right outermost point of the subject vehicle when the subject vehicle is in the intended travel path). The VTDs are parked one after the other and are facing in the same direction as the subject vehicle. One VTD is directly behind the other, separated by 1.0 ± 0.1 m. The subject vehicle must be able to avoid contact with the child PTM crossing its path. NHTSA specifies testing this scenario with a 50% overlap during daylight. The subject vehicle testing speed is any speed between 10 km/h and 50 km/h, while the child PTM speed is 5 km/h.

Pedestrian Test Mannequin—Obstructed From the Right

A child PTM is used for the obstructed scenario. NHTSA specifies that the child PTM is secured to a moving apparatus so that it faces the direction of motion at 4.0 ± 0.1 m to the right of the intended travel path. The PTM's leg articulation is to start on apparatus movement and stops when the apparatus stops. This scenario simulates a running child pedestrian and the child PTM speed is 5 km/h.

Test Conduct Prior to FCW or Vehicle Braking Onset

NHTSA specifies that, as the subject vehicle approaches the crossing path of the PTM, beginning when the headway corresponds to L_0, the subject vehicle speed be maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs. Furthermore, beginning when the headway corresponds to L_0, the subject vehicle heading is to be maintained with minimal steering input such that the subject vehicle travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s. Prior to the start of a test trial, as long as the specified initialization procedure is executed, a subject vehicle may be driven under any conditions including any speed and direction, and on any road surface, for any elapsed time prior to reaching the point where a test trial begins. For all tests, there is no specific limitations on how a subject vehicle is driven prior to the start of a test trail, in the same manner as for the lead vehicle trials.

The PTM apparatus is to be triggered at a time such that the pedestrian test mannequin meets the intended overlap. The agency specifies that the PTM achieve its intended speed within 1.5 m after the apparatus begins to move and maintains its intended speed within 0.4 km/h until the test completion criteria is satisfied.

Test Conduct After Either FCW or Vehicle Braking Onset

NHTSA specifies that after FCW or vehicle braking onset, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles with cruise control active.

During testing, no manual brake application is permitted and the PTM continues to move until one of the test completion criteria is satisfied.

Test Completion Criteria

NHTSA specifies that any test run is complete when the subject vehicle comes to a complete stop without making contact with the PTM, when the PTM is no longer in the forward path of the subject vehicle, or when the subject vehicle makes contact with the PTM.

Stationary Pedestrian

Test Parameters

The stationary pedestrian scenario consists of the subject vehicle traveling straight at a constant speed towards the adult PTM, which is stationary at an overlap of 25%, facing away from the approaching subject vehicle. The subject vehicle must be able to avoid contact with the stationary PTM during daylight and darkness with lower beam and upper beam. The subject vehicle testing speed is any speed between 10 km/h and 55 km/h.

Pedestrian Test Mannequin

An adult PTM is used for this scenario and NHTSA specifies that the PTM be stationary and face away from

the subject vehicle. The pedestrian test mannequin legs remain still.

Test Conduct Prior to FCW or Vehicle Braking Onset

NHTSA specifies that as the subject vehicle approaches the stationary PTM, beginning when the headway corresponds to L_0, the subject vehicle speed be maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs. Furthermore, beginning when the headway corresponds to L_0, the subject vehicle heading is to be maintained with minimal steering input such that the subject vehicle travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s. Similarly to the other tests, the subject vehicle may be driven under any conditions including any speed and direction, and on any road surface, for any elapsed time prior to reaching the point where a test trial begins.

Test Conduct After Either FCW or Vehicle Braking Onset

NHTSA specifies that after FCW or vehicle braking onset, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles with cruise control active. No manual braking is permitted during testing until one of the test completion criteria is satisfied.

Test Completion Criteria

NHTSA specifies that any test run is complete when the subject vehicle comes to a complete stop without making contact with the PTM or when the subject vehicle makes contact with the PTM.

Pedestrian Moving Along the Path

Test Parameters

The pedestrian moving along path scenario consists of the subject vehicle traveling straight at a constant speed towards an adult PTM moving away from the vehicle. The PTM is moving at 5 km/h at an overlap of 25%, facing away on the same travel path as the vehicle. The PTM's movement is parallel to and in the same direction as the subject vehicle. The subject vehicle must be able to avoid contact with the moving PTM during daylight and darkness with lower beam and upper beam. The subject vehicle testing speed is any speed between 10 km/h and 65 km/h.

Test Conduct Prior to FCW or Vehicle Braking Onset

NHTSA specifies that as the subject vehicle approaches the moving PTM, beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs. Furthermore, beginning when the headway corresponds to L_0, the subject vehicle heading is to be maintained with minimal steering input such that the subject vehicle travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s. Similarly to the other tests the subject vehicle may be driven under any conditions including any speed and direction, and on any road surface, for any elapsed time prior to reaching the point where a test trial begins.

The PTM is to be secured to a moving apparatus triggered any time after the distance between the front plane of the subject vehicle and a parallel contact plane on the pedestrian test mannequin corresponds to L_0. The specifications state that the PTM achieve its intended speed within 1.5 m after the apparatus begins to move and maintain its intended speed within 0.4 km/h until one of the test completion criteria is satisfied.

Test Conduct After Either FCW or Vehicle Braking Onset

NHTSA specifies that after FCW or vehicle braking onset, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles with cruise control active. No manual braking is permitted during testing until one of the test completion criteria is satisfied.

Test Completion Criteria

NHTSA specifies that any test run is complete when the subject vehicle slows to a speed below that of the PTM without making contact with the PTM, or when the subject vehicle makes contact with the PTM.

C. Appendix C: Description of the False Activation Test Procedures

Test Parameters

Headway Calculation

NHTSA specifies that for each test run conducted, the headway (L_0, $L_{2.1}$, $L_{1.1}$), in meters, between the front plane of the subject vehicle and either the steel trench plate's leading edge or the rearmost plane normal to the centerline of the vehicle test devices providing a 5.0 second, 2.1 second, and 1.1 second time to collision (TTC) is calculated. L_0, $L_{2.1}$, and $L_{1.1}$ are determined with the following equation where V_{SV} is the speed of the subject vehicle in m/s:

$L_x = TTC_x \times (V_{SV})$ *m*
TTC 0 = 5.0 s
TTC 2.1 = 2.1 s
TTC 1.1 = 1.1 s

Steel Trench Plate

Test Parameters

The steel trench plate false activation scenario involves the subject vehicle approaching at 80 km/h a steel plate, commonly used in road construction, placed on the surface of a test track in its intended travel path. The steel trench plate is positioned flat on the test surface so that its longest side is parallel to the vehicle's intended travel path and horizontally centered on the vehicle's intended travel path. The steel plate presents no imminent danger, and the subject vehicle can safely travel over the plate without harm. NHTSA specifies testing with and without manual brake application.

Test Conduct

The procedure states that as the subject vehicle approaches the steel trench plate, the subject vehicle speed shall be maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs beginning when the headway corresponds to L_0. Furthermore, beginning when the headway corresponds to L_0, the subject vehicle heading is to be maintained with minimal steering input such that the subject vehicle travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s. If an FCW occurs, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for tests performed with the subject vehicle's cruise control active.

For testing without manual brake application, no manual brake application is made until one of the test completion criteria is satisfied. For testing with manual brake application, the subject vehicle's accelerator pedal, if not already released, is released when the headway corresponds to $L_{2.1}$ at any rate such that it is fully released within 500 ms. The service brake application occurs at headway $L_{1.1.}$

Test Completion Criteria

The test run is complete when the subject vehicle comes to a stop prior to crossing over the leading edge of the steel trench plate or when the subject vehicle crosses over the leading edge of the steel trench plate.

Pass-through Test

Test Parameters

The pass-through test simulates the subject vehicle approaching at 80 km/h vehicle test devices secured in a stationary position parallel to one another with a lateral distance of 4.5 m ±0.1 m between the vehicles' closest front wheels. The centerline between the two vehicles is parallel to the intended travel path and the travel path is free of obstacles. NHTSA tests with and without manual brake application.

Test Conduct

The procedure states that as the subject vehicle approaches the gap between the two vehicle test devices, beginning when the headway corresponds to L_0, the subject vehicle speed be maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs. Furthermore, beginning when the headway corresponds to L_0, the subject vehicle heading is to be maintained with minimal steering input such that the subject vehicle travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s. If an FCW occurs, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles with cruise control active.

For testing without manual brake application, no manual brake application is made until one of the test completion criteria is satisfied. For testing with manual brake application, the subject vehicle's accelerator pedal, if not already released, is released when the headway corresponds to $L_{2.1}$ at any rate such that it is fully released within 500 ms. The service brake application occurs at headway $L_{1.1.}$

Test Completion Criteria

The test run is complete when the subject vehicle comes to a stop prior to its rearmost point passing the vertical plane connecting the forwardmost point of the vehicle test devices or when the rearmost point of the subject vehicle passes the vertical plane connecting the forwardmost point of the vehicle test devices.

List of Subjects

49 CFR Part 571

Imports, Incorporation by reference, Motor vehicle safety, Motor vehicles, Rubber and rubber products.

49 CFR Part 595

Motor vehicle safety, Motor vehicles.

49 CFR Part 596

Automatic emergency braking, Incorporation by reference, Motor vehicles, Motor vehicle safety, Test devices.

In consideration of the foregoing, NHTSA amends 49 CFR chapter V as follows:

PART 571—FEDERAL MOTOR VEHICLE SAFETY STANDARDS

■ 1. The authority citation for part 571 continues to read as follows:

Authority: 49 U.S.C. 322, 30111, 30115, 30117 and 30166; delegation of authority at 49 CFR 1.95.

■ 2. Amend § 571.5 by:
■ a. Revising paragraph (d)(35);
■ b. Redesignating paragraphs (l)(49) and (50) as paragraphs (l)(50) and (51), respectively; and
■ c. Adding new paragraph (l)(49).

The revision and addition read as follows:

§ 571.5 Matter incorporated by reference.

* * * * *

(d) * * *

(35) ASTM E1337–19, ''Standard Test Method for Determining Longitudinal Peak Braking Coefficient (PBC) of Paved Surfaces Using Standard Reference Test Tire,'' approved December 1, 2019, into §§ 571.105; 571.121; 571.122; 571.126; 571.127; 571.135; 571.136; 571.500.

* * * * *

(l) * * *

(49) SAE J2400, ''Human Factors in Forward Collision Warning Systems: Operating Characteristics and User Interface Requirements,'' August 2003 into § 571.127.

* * * * *

■ 3. Add § 571.127 to read as follows:

§ 571.127 Standard No. 127; Automatic emergency braking systems for light vehicles.

S1. *Scope.* This standard establishes performance requirements for automatic emergency braking (AEB) systems for light vehicles.

S2. *Purpose.* The purpose of this standard is to reduce the number of deaths and injuries that result from crashes in which drivers do not apply the brakes or fail to apply sufficient braking power to avoid or mitigate a crash.

S3. *Application.* This standard applies to passenger cars and to multipurpose passenger vehicles, trucks, and buses with a gross vehicle weight rating (GVWR) of 4,536 kilograms (10,000 pounds) or less.

S4. *Definitions.*

Adaptive cruise control system is an automatic speed control system that allows the equipped vehicle to follow a lead vehicle at a pre-selected gap by controlling the engine, power train, and service brakes.

Ambient illumination is the illumination as measured at the test surface, not including any illumination provided by the subject vehicle.

Automatic emergency braking (AEB) system is a system that detects an imminent collision with vehicles, objects, and road users in or near the path of a vehicle and automatically controls the vehicle's service brakes to avoid or mitigate the collision.

Brake pedal application onset is when 11 N of force has been applied to the brake pedal.

Forward collision warning is an auditory and visual warning provided to the vehicle operator by the AEB system that is designed to induce immediate forward crash avoidance response by the vehicle operator.

Forward collision warning onset is the first moment in time when a forward collision warning is provided.

Headway is the distance between the subject vehicle's frontmost plane normal to its centerline and as applicable: the vehicle test device's rearmost plane normal to its centerline; a parallel contact plane (to the subject vehicle's frontmost plane) on the pedestrian test mannequin; and the leading edge of the steel trench plate.

Lead vehicle is a vehicle test device facing the same direction and preceding a subject vehicle within the same travel lane.

Lead vehicle braking onset is the point at which the lead vehicle achieves a deceleration of 0.05 g due to brake application.

Masked threshold is the quietest level of a signal that can be perceived in the presence of noise.

Pedestrian test mannequin is a device used during AEB testing, when approaching pedestrians, meeting the specifications of subpart B of 49 CFR part 596.

Small-volume manufacturer means an original vehicle manufacturer that produces or assembles fewer than 5,000 vehicles annually for sale in the United States.

Steel trench plate is a rectangular steel plate often used in road construction to temporarily cover sections of pavement unsafe to drive over directly.

Subject vehicle is the vehicle under examination for compliance with this standard.

Travel path is the path projected onto the road surface of a point located at the intersection of the subject vehicle's frontmost vertical plane and

longitudinal vertical center plane, as the subject vehicle travels forward.

Subject vehicle braking onset is the point at which the subject vehicle achieves a deceleration of 0.15 g due to the automatic control of the service brakes.

Vehicle test device is a device meeting the specifications set forth in subpart C of 49 CFR part 596.

S5. *Requirements.*

(a) Except as provided in S5(b), vehicles manufactured on or after September 1, 2029 must meet the requirements of this standard.

(b) The requirements of S5(a) do not apply to small-volume manufacturers, final-stage manufacturers, and alterers until one year after the dates specified in S5(a).

S5.1. *Requirements when approaching a lead vehicle.*

S5.1.1. *Forward collision warning.* A vehicle is required to have a forward collision warning system, as defined in S4 that provides an auditory and visual signal to the driver of an impending collision with a lead vehicle. The system must operate under the conditions specified in S6 when traveling at any forward speed that is greater than 10 km/h (6.2 mph) and less than 145 km/h (90.1 mph).

(a) *Auditory signal.*

(1) The auditory signal must have a high fundamental frequency of at least 800 Hz.

(2) The auditory signal must have a tempo in the range of 6–12 pulses per second and a duty cycle in the range of 0.25–0.95.

(3) The auditory signal must have a minimum intensity of 15–30 dB above the masked threshold.

(4) In-vehicle audio that is not related to a safety purpose or safety system (*i.e.,* entertainment and other audio content not related to or essential for safe performance of the driving task) must be muted, or reduced in volume to within 5 dB of the masked threshold during presentation of the FCW auditory signal.

(b) *Visual signal.*

(1) The visual signal must be located within an ellipse that extends 18 degrees vertically and 10 degrees horizontally of the driver forward line of sight based on the forward-looking eye midpoint (M_f) as described in S14.1.5. of § 571.111.

(2) The visual signal must include the crash pictorial symbol in SAE J2400, 4.1.16, incorporated by reference (see § 571.5).

(3) The visual signal symbol must be red in color and steady burning.

S5.1.2. *Automatic emergency braking.* A vehicle is required to have an automatic emergency braking system, as defined in S4, that applies the service brakes automatically when a collision with a lead vehicle is imminent. The system must operate under the conditions specified in S6 when the vehicle is traveling at any forward speed that is greater than 10 km/h (6.2 mph) and less than 145 km/h (90.1 mph).

S5.1.3. *Performance test requirements.* The vehicle must provide a forward collision warning and subsequently apply the service brakes automatically when a collision with a lead vehicle is imminent such that the subject vehicle does not collide with the lead vehicle when tested using the procedures in S7 under the conditions specified in S6. The forward collision warning is not required if adaptive cruise control is engaged.

S5.2. *Requirements when approaching pedestrians.*

S5.2.1. *Forward collision warning.* A vehicle is required to have a forward collision warning system, as defined in S4, that provides an auditory and visual signal to the driver of an impending collision with a pedestrian. The system must operate under the conditions specified in S6 when the vehicle is traveling at any forward speed that is greater than 10 km/h (6.2 mph) and less than 73 km/h (45.3 mph). The forward collision warning system must meet the auditory signal and visual signal requirements specified in S5.1.1.

S5.2.2. *Automatic emergency braking.* A vehicle is required to have an automatic emergency braking system, as defined in S4, that applies the service brakes automatically when a collision with a pedestrian is imminent when the vehicle is under the conditions specified in S6 and is traveling at any forward speed that is greater than 10 km/h (6.2 mph) and less than 73 km/h (45.3 mph).

S5.2.3. *Performance test requirements.* The vehicle must provide a forward collision warning and apply the brakes automatically such that the subject vehicle does not collide with the pedestrian test mannequin when tested using the procedures in S8 under the conditions specified in S6.

S5.3. *False activation.* The vehicle must not automatically apply braking that results in peak additional deceleration that exceeds what manual braking would produce by 0.25 g or greater, when tested using the procedures in S9 under the conditions specified in S6.

S5.4. *Malfunction detection and controls.*

S5.4.1 The system must continuously detect system malfunctions, including performance degradation caused solely by sensor obstructions. If the system detects a malfunction, or if the system adjusts its performance such that it will not meet the requirements specified in S5.1, S5.2, or S5.3, the system must provide the vehicle operator with a telltale notification.

S5.4.2 Except as provided in S5.4.2.1 and S5.4.2.2, the manufacturer must not provide a control that will place the AEB system in a mode or modes in which it will no longer satisfy the performance requirements of S5.1, S5.2, and S5.3.

S5.4.2.1 The manufacturer may provide a control to allow AEB deactivation that is securely activated, provided the manufacturer enables such activation exclusively in a vehicle owned by a law enforcement agency.

S5.4.2.2 The manufacturer may allow AEB deactivation to occur during low-range four-wheel drive configurations, when the driver selects ''tow mode,'' or when another vehicle system is activated that will have a negative ancillary impact on AEB operation.

S5.4.3 The vehicle's AEB system must always return to the manufacturer's original default AEB mode that satisfies the requirements of S5.1, S5.2, and S5.3 at the initiation of each new ignition cycle, unless the vehicle is in a low-range four-wheel drive configuration selected by the driver on the previous ignition cycle designed for low-speed, off-road driving.

S6. *Test conditions.*

S6.1. *Environmental conditions.*

S6.1.1. *Temperature.* The ambient temperature is any temperature between 0 °C and 40 °C.

S6.1.2. *Wind.* The maximum wind speed is no greater than 10 m/s (22 mph) during lead vehicle avoidance tests and 6.7 m/s (15 mph) during pedestrian avoidance tests.

S6.1.3. *Ambient lighting.*

(a) *Daylight testing.*

(1) The ambient illumination on the test surface is any level at or above 2,000 lux.

(2) Testing is not performed while driving toward or away from the sun such that the horizontal angle between the sun and a vertical plane containing the centerline of the subject vehicle is less than 25 degrees and the solar elevation angle is less than 15 degrees.

(b) *Dark testing.*

(1) The ambient illumination on the test surface is any level at or below 0.2 lux.

(2) Testing is performed under any lunar phase.

(3) Testing is not performed while driving toward the moon such that the horizontal angle between the moon and a vertical plane containing the centerline of the subject vehicle is less

than 25 degrees and the lunar elevation angle is less than 15 degrees.

S6.1.4. *Precipitation.* Testing is not conducted during periods of precipitation or when visibility is affected by fog, smoke, ash, or other particulate.

S6.2. *Road conditions.*

S6.2.1. *Test Track surface and construction.* The tests are conducted on a dry, uniform, solid-paved surface. Surfaces with debris, irregularities, or undulations, such as loose pavement, large cracks, or dips may not be used.

S6.2.2. *Surface friction.* The road test surface produces a peak friction coefficient (PFC) of 1.02 when measured using an ASTM F2493 standard reference test tire, in accordance with ASTM E1337–19 (incorporated by reference, see § 571.5), at a speed of 64 km/h (40 mph), without water delivery.

S6.2.3. *Slope.* The test surface has any consistent slope between 0 percent and 1 percent.

S6.2.4. *Markings.* The road surface within 2 m of the intended travel path is marked with zero, one, or two lines of any configuration or color. If one line is used, it is straight. If two lines are used, they are straight, parallel to each other, and at any distance from 2.7 m to 4.5 m apart.

S6.2.5. *Obstructions.* Testing is conducted such that the vehicle does not travel beneath any overhead structures, including but not limited to overhead signs, bridges, or gantries. No vehicles, obstructions, or stationary objects are within 7.4 m of either side of the intended travel path except as specified.

S6.3. *Subject vehicle conditions.*

S6.3.1. *Malfunction notification.* Testing is not conducted while the AEB malfunction telltale specified in S5.4 is illuminated.

S6.3.2. *Sensor obstruction.* All sensors used by the system and any part of the vehicle immediately ahead of the sensors, such as plastic trim, the windshield, etc., are free of debris or obstructions.

S6.3.3. *Tires.* The vehicle is equipped with the original tires present at the time of initial sale. The tires are inflated to the vehicle manufacturer's recommended cold tire inflation pressure(s) specified on the vehicle's placard or the tire inflation pressure label.

S6.3.4. *Brake burnish.*

(a) Vehicles subject to § 571.105 are burnished in accordance with S7.4 of § 571.105.

(b) Vehicles subject to § 571.135 are burnished in accordance with S7.1 of § 571.135.

S6.3.5. *Brake temperature.* The average temperature of the service brakes on the hottest axle of the vehicle during testing, measured according to S6.4.1 of § 571.135, is between 65°C and 100°C prior to braking.

S6.3.6. *Fluids.* All non-consumable fluids for the vehicle are at 100 percent capacity. All consumable fluids are at any level from 5 to 100 percent capacity.

S6.3.7. *Propulsion battery charge.* The propulsion batteries are charged at any level from 5 to 100 percent capacity.

S6.3.8. *Cruise control.* Cruise control, including adaptive cruise control, is configured under any available setting.

S6.3.9. *Adjustable forward collision warning.* Forward collision warning is configured in any operator-configurable setting.

S6.3.10. *Engine braking.* A vehicle equipped with an engine braking system that is engaged and disengaged by the operator is tested with the system in any selectable configuration.

S6.3.11. *Regenerative braking.* Regenerative braking is configured under any available setting.

S6.3.12. *Headlamps.*

(a) Daylight testing is conducted with the headlamp control in any selectable position.

(b) Darkness testing is conducted with the vehicle's lower beams active and separately with the vehicle's upper beams active.

(c) Prior to performing darkness testing, headlamps are aimed according to the vehicle manufacturer's instructions. The weight of the loaded vehicle at the time of headlamp aiming is within 10 kg of the weight of the loaded vehicle during testing.

S6.3.13. *Subject vehicle loading.* The vehicle load, which is the sum of any vehicle occupants and any test equipment and instrumentation, does not exceed 277 kg. The load does not cause the vehicle to exceed its GVWR or any axle to exceed its GAWR.

S6.3.14. *AEB system initialization.* The vehicle is driven at a speed of 10 km/h or higher for at least one minute prior to testing, and subsequently the starting system is not cycled off prior to testing.

S6.4. *Equipment and test devices.*

S6.4.1. The vehicle test device is specified in 49 CFR part 596, subpart C. Local fluttering of the lead vehicle's external surfaces does not exceed 10 mm perpendicularly from the reference surface, and distortion of the lead vehicle's overall shape does not exceed 25 mm in any direction.

S6.4.2. Adult pedestrian test mannequin is specified in 49 CFR part 596, subpart B.

S6.4.3. Child pedestrian test mannequin is specified in 49 CFR part 596, subpart B.

S6.4.4. The steel trench plate used for the false activation test has the dimensions 2.4 m x 3.7 m x 25 mm and is made of ASTM A36 steel. Any metallic fasteners used to secure the steel trench plate are flush with the top surface of the steel trench plate.

S7. *Testing when approaching a lead vehicle.*

S7.1. *Setup.*

(a) The testing area is set up in accordance with figure 2 to this section.

(b) Testing is conducted during daylight.

(c) For reference, table 1 to S7.1 specifies the subject vehicle speed (V_{SV}), lead vehicle speed (V_{LV}), headway, and lead vehicle deceleration for each test that may be conducted.

(d) The intended travel path of the vehicle is a straight line toward the lead vehicle from the location corresponding to a headway of L_0.

(e) If the road surface is marked with a single or double lane line, the intended travel path is parallel to and 1.8 m from the inside of the closest line. If the road surface is marked with two lane lines bordering the lane, the intended travel path is centered between the two lines.

(f) For each test run conducted, the subject vehicle speed (V_{SV}), lead vehicle speed (V_{LV}), headway, and lead vehicle deceleration will be selected from the ranges specified in table 1 to S7.1.

TABLE 1 TO S7.1—TEST PARAMETERS WHEN APPROACHING A LEAD VEHICLE

	Speed (km/h)		Headway (m)	Lead vehicle decel (g)	Manual brake application
	V_{SV}	V_{LV}			
Stopped Lead Vehicle	Any 10–80	0	—	—	No.
	Any 70–100	0	—	—	Yes.
Slower-Moving Lead Vehicle	Any 40–80	20	—	—	No.
	Any 70–100	20	—	—	Yes.

TABLE 1 TO S7.1—TEST PARAMETERS WHEN APPROACHING A LEAD VEHICLE—Continued

	Speed (km/h)		Headway (m)	Lead vehicle decel (g)	Manual brake application
	V_{SV}	V_{LV}			
Decelerating Lead Vehicle	50	50	Any 12–40	Any 0.3–0.5	No.
	50	50	Any 12–40	Any 0.3–0.5	Yes.
	80	80	Any 12–40	Any 0.3–0.5	No.
	80	80	Any 12–40	Any 0.3–0.5	Yes.

S7.2. *Headway calculation.* For each test run conducted under S7.3 and S7.4, the headway (L_0), in meters, providing 5.0 seconds time to collision (*TTC*) is calculated. L_0 is determined with the following equation where V_{SV} is the speed of the subject vehicle in m/s and V_{LV} is the speed of the lead vehicle in m/s:

Equation 1 to S7.2

$$L_0 = \mathrm{TTC}_0 \times (V_{SV} - V_{LV})$$
$$\mathrm{TTC}_0 = 5.0$$

S7.3. *Stopped lead vehicle.*

S7.3.1. *Test parameters.*

(a) For testing with no subject vehicle manual brake application, the subject vehicle test speed is any speed between 10 km/h and 80 km/h, and the lead vehicle speed is 0 km/h.

(b) For testing with manual brake application of the subject vehicle, the subject vehicle test speed is any speed between 70 km/h and 100 km/h, and the lead vehicle speed is 0 km/h.

S7.3.2. *Test conduct prior to forward collision warning onset.*

(a) The lead vehicle is placed stationary with its longitudinal centerline coincident to the intended travel path.

(b) Before the headway corresponds to L_0, the subject vehicle is driven at any speed, in any direction, on any road surface, for any amount of time.

(c) The subject vehicle approaches the rear of the lead vehicle.

(d) Beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs.

(e) Beginning when the headway corresponds to L_0, the subject vehicle heading is maintained with minimal steering input such that the travel path does not deviate more than 0.3 m laterally from the intended travel path and the subject vehicle's yaw rate does not exceed ±1.0 deg/s.

S7.3.3. *Test conduct after forward collision warning onset.*

(a) The accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles tested with cruise control active.

(b) For testing conducted with manual brake application, the service brakes are applied as specified in S10. The onset of brake pedal application occurs 1.0 ± 0.1 second after forward collision warning onset.

(c) For testing conducted without manual brake application, no manual brake application is made until the test completion criteria of S7.3.4 are satisfied.

S7.3.4. *Test completion criteria.* The test run is complete when the subject vehicle comes to a complete stop without making contact with the lead vehicle or when the subject vehicle makes contact with the lead vehicle.

S7.4. *Slower-moving lead vehicle.*

S7.4.1. *Test parameters.*

(a) For testing with no subject vehicle manual brake application, the subject vehicle test speed is any speed between 40 km/h and 80 km/h, and the lead vehicle speed is 20 km/h.

(b) For testing with manual brake application of the subject vehicle, the subject vehicle test speed is any speed between 70 km/h and 100 km/h, and the lead vehicle speed is 20 km/h.

S7.4.2. *Test conduct prior to forward collision warning onset.*

(a) The lead vehicle is propelled forward in a manner such that the longitudinal center plane of the lead vehicle does not deviate laterally more than 0.3m from the intended travel path.

(b) The subject vehicle approaches the lead vehicle.

(c) Before the headway corresponds to L_0, the subject vehicle is driven at any speed, in any direction, on any road surface, for any amount of time.

(d) Beginning when the headway corresponds to L_0, the subject vehicle and lead vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs.

(e) Beginning when the headway corresponds to L_0, the subject vehicle and lead vehicle headings are be maintained with minimal steering input such that the subject vehicle's travel path does not deviate more than 0.3 m laterally from the centerline of the lead vehicle, and the yaw rate of the subject vehicle does not exceed ±1.0 deg/s prior to the forward collision warning onset.

S7.4.3. *Test conduct after forward collision warning onset.*

(a) The subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles tested with cruise control active.

(b) For testing conducted with manual braking application, the service brakes are applied as specified in S10. The onset of brake pedal application is 1.0 ±0.1 second after the forward collision warning onset.

(c) For testing conducted without manual braking application, no manual brake application is made until the test completion criteria of S7.4.4 are satisfied.

S7.4.4. *Test completion criteria.* The test run is complete when the subject vehicle speed is less than or equal to the lead vehicle speed without making contact with the lead vehicle or when the subject vehicle makes contact with the lead vehicle.

S7.5. *Decelerating lead vehicle.*

S7.5.1. *Test parameters.*

(a) The subject vehicle test speed is 50 km/h or 80 km/h, and the lead vehicle speed is identical to the subject vehicle test speed.

(b) [Reserved]

S7.5.2. *Test conduct prior to lead vehicle braking onset.*

(a) Before the 3 seconds prior to lead vehicle braking onset, the subject vehicle is be driven at any speed, in any direction, on any road surface, for any amount of time.

(b) Between 3 seconds prior to lead vehicle braking onset and lead vehicle braking onset:

(1) The lead vehicle is propelled forward in a manner such that the longitudinal center plane of the vehicle does not deviate laterally more than 0.3 m from the intended travel path.

(2) The subject vehicle follows the lead vehicle at a headway of any distance between 12 m and 40 m.

(3) The subject vehicle's speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs prior to forward collision warning onset.

(4) The lead vehicle's speed is maintained within 1.6 km/h.

(5) The subject vehicle and lead vehicle headings are maintained with minimal steering input such that their travel paths do not deviate more than 0.3 m laterally from the centerline of the lead vehicle, and the yaw rate of the subject vehicle does not exceed ±1.0 deg/s until onset of forward collision warning.

S7.5.3. *Test conduct following lead vehicle braking onset.*

(a) The lead vehicle is decelerated to a stop with a targeted average deceleration of any value between 0.3g and 0.5g. The targeted deceleration magnitude is achieved within 1.5 seconds of lead vehicle braking onset and is maintained until 250 ms prior to coming to a stop.

(b) After forward collision warning onset, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles with cruise control active.

(c) For testing conducted with manual braking application, the service brakes are applied as specified in S10. The brake pedal application onset occurs 1.0 ± 0.1 second after the forward collision warning onset.

(d) For testing conducted without manual braking application, no manual brake application is made until the test completion criteria of S7.5.4 are satisfied.

S7.5.4. *Test completion criteria.* The test run is complete when the subject vehicle comes to a complete stop without making contact with the lead vehicle or when the subject vehicle makes contact with the lead vehicle.

S8. *Testing when approaching a pedestrian.*

S8.1. *Setup.*

S8.1.1. *General.*

(a) For reference, table 2 to S8.1.1 specifies the pedestrian test mannequin direction of travel, overlap, obstruction condition and speed (V_P), the subject vehicle speed (V_{SV}), and the lighting condition for each test that may be conducted.

(b) The intended travel path of the vehicle is a straight line originating at the location corresponding to a headway of L_0.

(c) If the road surface is marked with a single or double lane line, the intended travel path is parallel to and 1.8 m from the inside of the closest line. If the road surface is marked with two lane lines bordering the lane, the intended travel path is centered between the two lines.

(d) For each test run conducted, the subject vehicle speed (V_{SV}) will be selected from the range specified in table 2 to S8.1.1.

TABLE 2 TO S8.1.1—TEST PARAMETERS WHEN APPROACHING A PEDESTRIAN

	Direction	Overlap	Obstructed	Speed (km/h)		Lighting condition
				V_{SV}	V_P	
Pedestrian Crossing Road.	Right	25	No	Any 10–60	5	Daylight
	Right	50	No	Any 10–60	5	Daylight Lower Beams Upper Beams
	Left	50	No	Any 10–60	8	Daylight
	Right	50	Yes	Any 10–50	5	Daylight
Stationary Pedestrian	Right	25	No	Any 10–55	0	Daylight Lower Beams Upper Beams
Pedestrian Moving Along the Path.	Right	25	No	Any 10–65	5	Daylight Lower Beams Upper Beams

S8.1.2. *Overlap.* As depicted in figure 1 to this section, overlap describes the location of the point on the front of the subject vehicle that would make contact with a pedestrian if no braking occurred. Overlap is the percentage of the subject vehicle's overall width that the pedestrian test mannequin traverses. It is measured from the right or the left, depending on the side of the subject vehicle where the pedestrian test mannequin originates. For each test run, the actual overlap will be within 0.15 m of the specified overlap.

S8.1.3. *Pedestrian test mannequin.*

(a) For testing where the pedestrian test mannequin is secured to a moving apparatus, the pedestrian test mannequin is secured so that it faces the direction of motion. The pedestrian test mannequin leg articulation starts on apparatus movement and stops when the apparatus stops.

(b) For testing where the pedestrian test mannequin is stationary, the pedestrian test mannequin faces away from the subject vehicle, and the pedestrian test mannequin legs remain still.

S8.2. *Headway calculation.* For each test run conducted under S8.3, S8.4, and S8.5, the headway (L_0), in meters, providing 4.0 seconds time to collision (TTC) is calculated. L_0 is determined with the following equation where V_{SV} is the speed of the subject vehicle in m/s and $V_{P\text{-}y}$ is the component of speed of the pedestrian test mannequin in m/s in the direction of the intended travel path:

Equation 2 to S8.2

$$L_0 = TTC_0 \times (V_{SV} - V_{P\text{-}y})$$

$$TTC_0 = 4.0$$

S8.3. *Pedestrian crossing road.*

S8.3.1. *Test parameters and setup (unobstructed from right).*

(a) The testing area is set up in accordance with figure 3 to this section.

(b) Testing is conducted in the daylight or darkness conditions, except that testing with the pedestrian at the 25 percent overlap is only conducted in daylight conditions.

(c) Testing is conducted using the adult pedestrian test mannequin.

(d) The movement of the pedestrian test mannequin is perpendicular to the subject vehicle's intended travel path.

(e) The pedestrian test mannequin is set up 4.0 ± 0.1 m to the right of the intended travel path.

(f) The intended overlap is 25 percent from the right or 50 percent.

(g) The subject vehicle test speed is any speed between 10 km/h and 60 km/h.

(h) The pedestrian test mannequin speed is 5 km/h.

S8.3.2 *Test parameters and setup (unobstructed from left).*

(a) The testing area is set up in accordance with figure 4 to this section.

(b) Testing is conducted in the daylight condition.

(c) Testing is conducted using the adult pedestrian mannequin.

(d) The movement of the pedestrian test mannequin is perpendicular to the intended travel path.

(e) The pedestrian test mannequin is set up 6.0 ± 0.1 m to the left of the intended travel path.

(f) The intended overlap is 50 percent.

(g) The subject vehicle test speed is any speed between 10 km/h and 60 km/h.

(h) The pedestrian test mannequin speed is 8 km/h.

S8.3.3. *Test parameters and setup (obstructed).*

(a) The testing area is set up in accordance with figure 5 to this section.

(b) Testing is conducted in the daylight condition.

(c) Testing is conducted using the child pedestrian test mannequin.

(d) The movement of the pedestrian test mannequin is perpendicular to the intended travel path.

(e) The pedestrian test mannequin is set up 4.0 ± 0.1 m to the right of the intended travel path.

(f) The intended overlap is 50 percent.

(g) Two vehicle test devices are secured in stationary positions parallel to the intended travel path. The two vehicle test devices face the same direction as the intended travel path. One vehicle test device is directly behind the other separated by 1.0 ± 0.1 m. The frontmost plane of the vehicle test device furthermost from the subject vehicle is located 1.0 ± 0.1 m from the parallel contact plane (to the subject vehicle's frontmost plane) on the pedestrian test mannequin. The left side of each vehicle test device is 1.0 ± 0.1 m to the right of the vertical plane parallel to the intended travel path and tangent with the right outermost point of the subject vehicle when the subject vehicle is in the intended travel path.

(h) The subject vehicle test speed is any speed between 10 km/h and 50 km/h.

(i) The pedestrian test mannequin speed is 5 km/h.

S8.3.4. *Test conduct prior to forward collision warning or subject vehicle braking onset.*

(a) Before the headway corresponds to L_0, the subject vehicle is driven at any speed, in any direction, on any road surface, for any amount of time.

(b) The subject vehicle approaches the crossing path of the pedestrian test mannequin.

(c) Beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs.

(d) Beginning when the headway corresponds to L_0, the subject vehicle heading is maintained with minimal steering inputs such that the subject vehicle's travel path does not deviate more than 0.3 m laterally from the intended travel path, and the yaw rate of the subject vehicle does not exceed ±1.0 deg/s prior to any automated braking onset.

(e) The pedestrian test mannequin apparatus is triggered at a time such that the pedestrian test mannequin meets the intended overlap, subject to the criteria in S8.1.2. The pedestrian test mannequin achieves its intended speed within 1.5 m after the apparatus begins to move and maintains its intended speed within 0.4 km/h until the test completion criteria of S8.3.6 are satisfied.

S8.3.5. *Test conduct after either forward collision warning or subject vehicle braking onset.*

(a) After forward collision warning or subject vehicle braking onset, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles with cruise control active.

(b) No manual brake application is made until the test completion criteria of S8.3.6 are satisfied.

(c) The pedestrian mannequin continues to move until the completion criteria of S8.3.6 are satisfied.

S8.3.6. *Test completion criteria.* The test run is complete when the subject vehicle comes to a complete stop without making contact with the pedestrian test mannequin, when the pedestrian test mannequin is no longer in the path of the subject vehicle, or when the subject vehicle makes contact with the pedestrian test mannequin.

S8.4. *Stationary pedestrian.*

S8.4.1. *Test parameters and setup.*

(a) The testing area is set up in accordance with figure 6 to this section.

(b) Testing is conducted in the daylight or darkness conditions.

(c) Testing is conducted using the adult pedestrian test mannequin.

(d) The pedestrian mannequin is set up at the 25 percent right overlap position facing away from the approaching vehicle.

(e) The subject vehicle test speed is any speed between 10 km/h and 55 km/h.

(f) The pedestrian mannequin is stationary.

S8.4.2. *Test conduct prior to forward collision warning or subject vehicle braking onset.*

(a) Before the headway corresponds to L_0, the subject vehicle is driven at any speed, in any direction, on any road surface, for any amount of time.

(b) The subject vehicle approaches the pedestrian test mannequin.

(c) Beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs.

(d) Beginning when the headway corresponds to L_0, the subject vehicle heading is maintained with minimal steering inputs such that the subject vehicle's travel path does not deviate more than 0.3 m laterally from the intended travel path, and the yaw rate of the subject vehicle does not exceed ±1.0 deg/s prior to any automated braking onset.

S8.4.3. *Test conduct after either forward collision warning or subject vehicle braking onset.*

(a) After forward collision warning or subject vehicle braking onset, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted with vehicles with cruise control active.

(b) No manual brake application is made until the test completion criteria of S8.4.4 are satisfied.

S8.4.4. *Test completion criteria.* The test run is complete when the subject vehicle comes to a complete stop without making contact with the pedestrian test mannequin, or when the subject vehicle makes contact with the pedestrian test mannequin.

S8.5. *Pedestrian moving along the path.*

S8.5.1. *Test parameters and setup.*

(a) The testing area is set up in accordance with figure 7 to this section.

(b) Testing is conducted in the daylight or darkness conditions.

(c) Testing is conducted using the adult pedestrian test mannequin.

(d) The movement of the pedestrian test mannequin is parallel to and in the same direction as the subject vehicle.

(e) The pedestrian test mannequin is set up in the 25 percent right offset position.

(f) The subject vehicle test speed is any speed between 10 km/h and 65 km/h.

(g) The pedestrian test mannequin speed is 5 km/h.

S8.5.2. *Test conduct prior to forward collision warning or subject vehicle braking onset.*

(a) Before the headway corresponds to L_0, the subject vehicle is driven at any speed, in any direction, on any road surface, for any amount of time.

(b) The subject vehicle approaches the pedestrian test mannequin.

(c) Beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs.

(d) Beginning when the headway corresponds to L_0, the subject vehicle heading is maintained with minimal steering inputs such that the travel path does not deviate more than 0.3 m laterally from the intended travel path, and the yaw rate of the subject vehicle does not exceed ±1.0 deg/s prior to any automated braking onset.

(e) The pedestrian test mannequin apparatus is triggered any time after the distance between the front plane of the subject vehicle and a parallel contact plane on the pedestrian test mannequin corresponds to L_0. The pedestrian test mannequin achieves its intended speed within 1.5 m after the apparatus begins to move and maintains its intended speed within 0.4 km/h until the test completion criteria of S8.5.4 are satisfied.

S8.5.3. *Test conduct after either forward collision warning or subject vehicle braking onset.*

(a) After forward collision warning or subject vehicle braking onset, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles with cruise control active.

(b) No manual brake application is made until the test completion criteria of S8.5.4 are satisfied.

S8.5.4. *Test completion criteria.* The test run is complete when the subject vehicle slows to speed below the pedestrian test mannequin travel speed without making contact with the pedestrian test mannequin or when the subject vehicle makes contact with the pedestrian test mannequin.

S9. *False AEB activation.*

S9.1. *Headway calculation.* For each test run to be conducted under S9.2 and S9.3, the headway (L_0, $L_{2.1}$, $L_{1.1}$), in meters, providing 5.0 seconds, 2.1 seconds, and 1.1 seconds time to collision (TTC) is calculated. L_0, $L_{2.1}$, and $L_{1.1}$ are determined with the following equation where V_{SV} is the speed of the subject vehicle in m/s:

Equation 3 to S9.1

$$L_x = TTC_x \times (V_{SV})$$

$TTC_0 = 5.0$

$TTC_{2.1} = 2.1$

$TTC_{1.1} = 1.1$

S9.2. *Steel trench plate.*

S9.2.1. *Test parameters and setup.*

(a) The testing area is set up in accordance with figure 8 to this section.

(b) The steel trench plate is secured flat on the test surface so that its longest side is parallel to the vehicle's intended travel path and horizontally centered on the vehicle's intended travel path.

(c) The subject vehicle test speed is 80 km/h.

(d) Testing is conducted with manual brake application and without manual brake application.

(e) Testing is conducted during daylight.

S9.2.2. *Test conduct.*

(a) Before the headway corresponds to L_0, the subject vehicle is driven at any speed, in any direction, on any road surface, for any amount of time.

(b) The subject vehicle approaches the steel trench plate.

(c) Beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h of the test speed with minimal and smooth accelerator pedal inputs.

(d) Beginning when the headway corresponds to L_0, the subject vehicle heading is maintained with minimal steering input such that the travel path does not deviate more than 0.3 m laterally from the intended travel path, and the yaw rate of the subject vehicle does not exceed ±1.0 deg/s.

(e) If forward collision warning occurs, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms. This action is omitted for vehicles with cruise control active.

(f) For tests where no manual brake application occurs, manual braking is not applied until the test completion criteria of S9.2.3 are satisfied.

(g) For tests where manual brake application occurs, the subject vehicle's accelerator pedal, if not already released, is released when the headway corresponds to $L_{2.1}$ at any rate such that it is fully released within 500 ms.

(h) For tests where manual brake application occurs, the service brakes are applied as specified in S10. The brake application pedal onset occurs at headway $L_{1.1}$.

S9.2.3. *Test completion criteria.* The test run is complete when the subject vehicle comes to a stop prior to crossing over the leading edge of the steel trench plate or when the subject vehicle crosses over the leading edge of the steel trench plate.

S9.3. *Pass-through.*

S9.3.1. *Test parameters and setup.*

(a) The testing area is set up in accordance with figure 9 to this section.

(b) Two vehicle test devices are secured in a stationary position parallel to one another with a lateral distance of 4.5 m ±0.1 m between the vehicles' closest front wheels. The centerline between the two vehicles is parallel to the intended travel path.

(c) The subject vehicle test speed is 80 km/h.

(d) Testing is conducted with manual brake application and without manual brake application.

(e) Testing is conducted during daylight.

S9.3.2. *Test conduct.*

(a) Before the headway corresponds to L_0, the subject vehicle is driven at any speed, in any direction, on any road surface, for any amount of time.

(b) The subject vehicle approaches the gap between the two vehicle test devices.

(c) Beginning when the headway corresponds to L_0, the subject vehicle speed is maintained within 1.6 km/h with minimal and smooth accelerator pedal inputs.

(d) Beginning when the headway corresponds to L_0, the subject vehicle heading is maintained with minimal steering input such that the travel path does not deviate more than 0.3 m laterally from the intended travel path, and the yaw rate of the subject vehicle does not exceed ±1.0 deg/s.

(e) If forward collision warning occurs, the subject vehicle's accelerator pedal is released at any rate such that it is fully released within 500 ms.

(f) For tests where no manual brake application occurs, manual braking is not applied until the test completion criteria of S9.3.3 are satisfied.

(g) For tests where manual brake application occurs, the subject vehicle's accelerator pedal, if not already released, is released when the headway corresponds to $L_{2.1}$ at any rate such that it is fully released within 500 ms.

(h) For tests where manual brake application occurs, the service brakes are applied as specified in S10. The brake application onset occurs when the headway corresponds to $L_{1.1}$.

S9.3.3. *Test completion criteria.* The test run is complete when the subject vehicle comes to a stop prior to its rearmost point passing the vertical plane connecting the forwardmost point of the vehicle test devices or when the rearmost point of the subject vehicle passes the vertical plane connecting the forwardmost point of the vehicle test devices.

S10. *Subject vehicle brake application procedure.*

S10.1. The procedure begins with the subject vehicle brake pedal in its natural resting position with no preload or position offset.

S10.2. At the option of the manufacturer, either displacement feedback, hybrid feedback, or force feedback control is used.

S10.3. *Displacement feedback procedure.* For displacement feedback, the commanded brake pedal position is the brake pedal position that results in a mean deceleration of 0.4 g in the absence of AEB system activation.

(a) The mean deceleration is the deceleration over the time from the brake pedal achieving the commanded position to 250 ms before the vehicle comes to a stop.

(b) The pedal displacement controller displaces the brake pedal at a rate of 254 mm/s ±25.4 mm/s to the commanded brake pedal position.

(c) The pedal displacement controller may overshoot the commanded position by any amount up to 20 percent. If such an overshoot occurs, it is corrected within 250 ms from when the commanded position is first achieved.

(d) The achieved brake pedal position is any position within 10 percent of the commanded position from 250 ms after the commanded brake pedal position is first achieved to the end of the test.

S10.4. *Hybrid brake pedal feedback procedure.* For hybrid brake pedal feedback, the commanded brake pedal application is the brake pedal position and a subsequent commanded brake pedal force that results in a mean deceleration of 0.4 g in the absence of AEB system activation.

(a) The mean deceleration is the deceleration over the time from the brake pedal achieving the commanded position to 250 ms before the vehicle comes to a stop.

(b) The hybrid controller displaces the brake pedal at a rate of 254 mm/s ±25.4 mm/s to the commanded pedal position.

(c) The hybrid controller may overshoot the commanded position by any amount up to 20 percent. If such an overshoot occurs, it is corrected within 250 ms from then the commanded position is first achieved.

(d) The hybrid controller begins to control the force applied to the brake pedal and stops controlling pedal displacement within 100 ms after the commanded brake pedal displacement occurs.

(e) The hybrid controller applies a pedal force of at least 11.1 N from the onset of the brake application until the end of the test.

(f) The average pedal force is maintained within 10 percent of the commanded brake pedal force from 350 ms after commended pedal displacement occurs until test completion.

S10.5. *Force feedback procedure.* For force feedback, the commanded brake pedal application is the brake pedal force that results in a mean deceleration of 0.4 g in the absence of AEB system activation.

(a) The mean deceleration is the deceleration over the time from when the commanded brake pedal force is first achieved to 250 ms before the vehicle comes to a stop.

(b) The force controller achieves the commanded brake pedal force within 250 ms. The application rate is unrestricted.

(c) The force controller may overshoot the commanded force by any amount up to 20 percent. If such an overshoot occurs, it is corrected within 250 ms from when the commanded force is first achieved.

(d) The force controller applies a pedal force of at least 11.1 N from the onset of the brake application until the end of the test.

(e) The average pedal force is maintained within 10 percent of the commanded brake pedal force from 250 ms after commended pedal force occurs until test completion.

BILLING CODE 4910–59–P

Figure 1 to § 571.127—Percentage Overlap Nomenclature

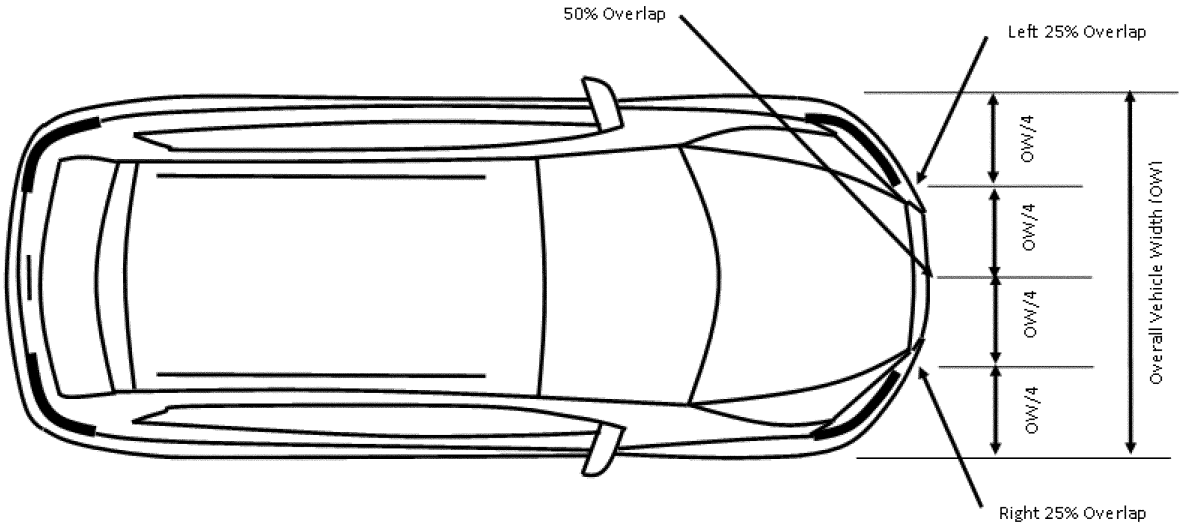


Figure 2 to § 571.127—Setup for Lead Vehicle Automatic Emergency Braking

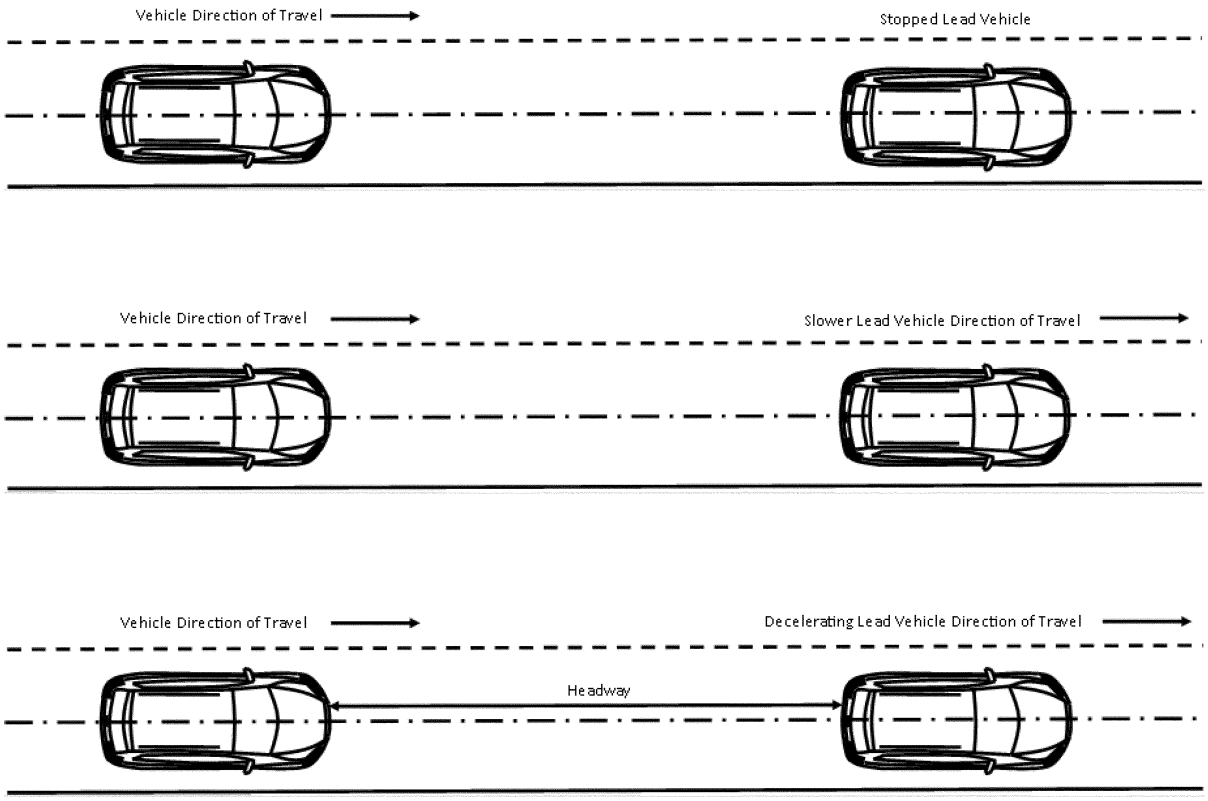


Figure 3 to § 571.127—Setup for Pedestrian, Crossing Path, Right

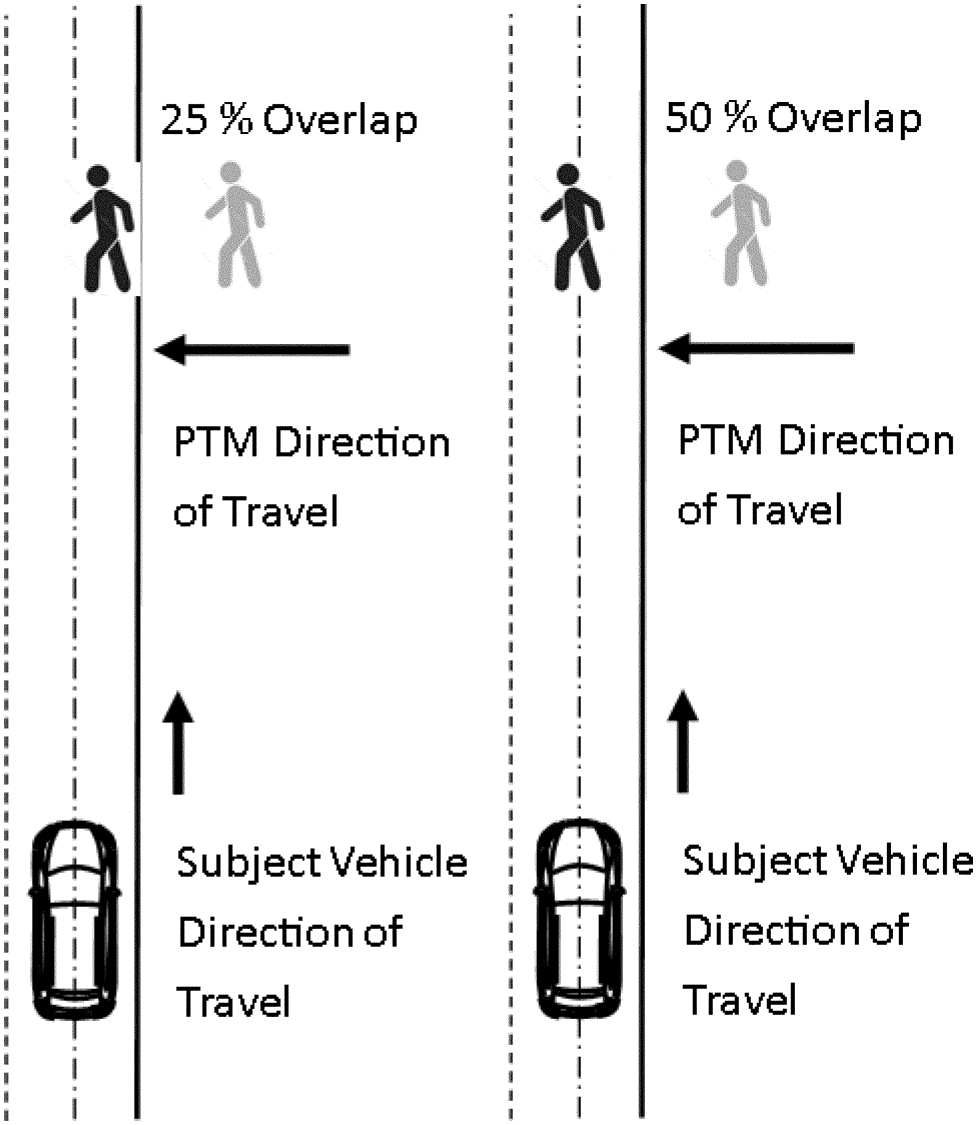


Figure 4 to § 571.127—Setup for Pedestrian, Crossing Path, Left

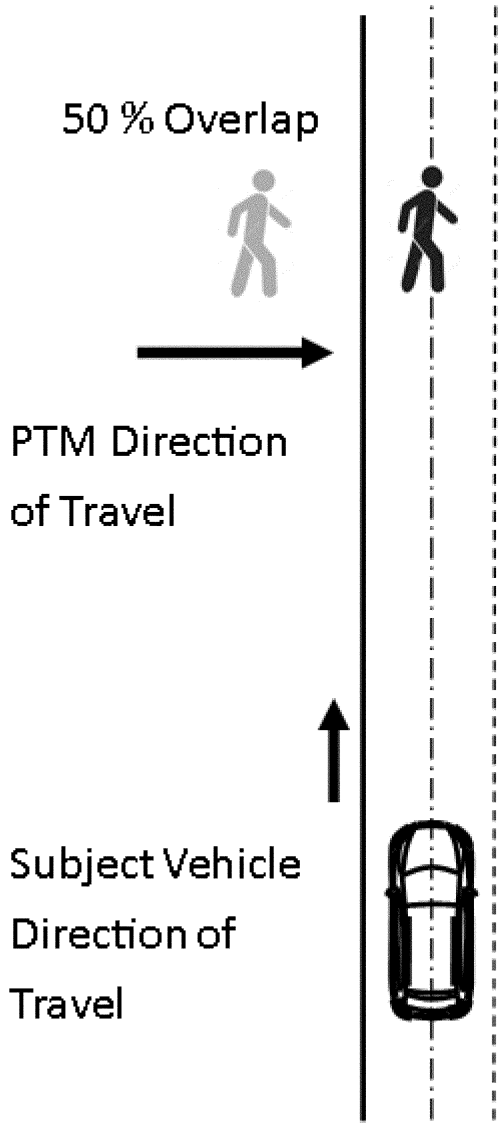


Figure 5 to § 571.127—Setup for Pedestrian, Obstructed

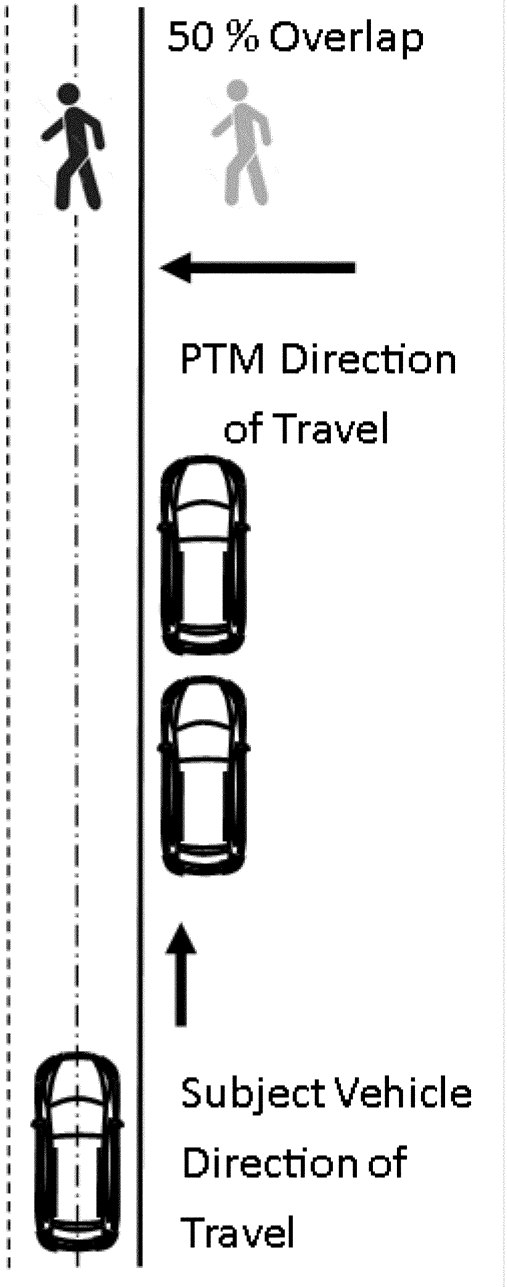


Figure 6 to § 571.127—Setup for Pedestrian Along-Path Stationary

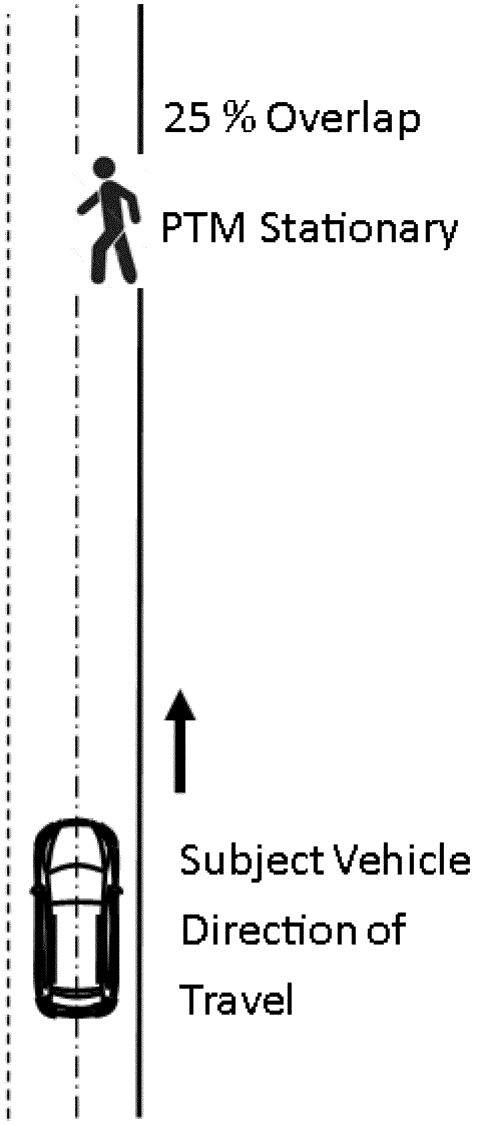


Figure 7 to § 571.127—Setup for Pedestrian Along-Path Moving

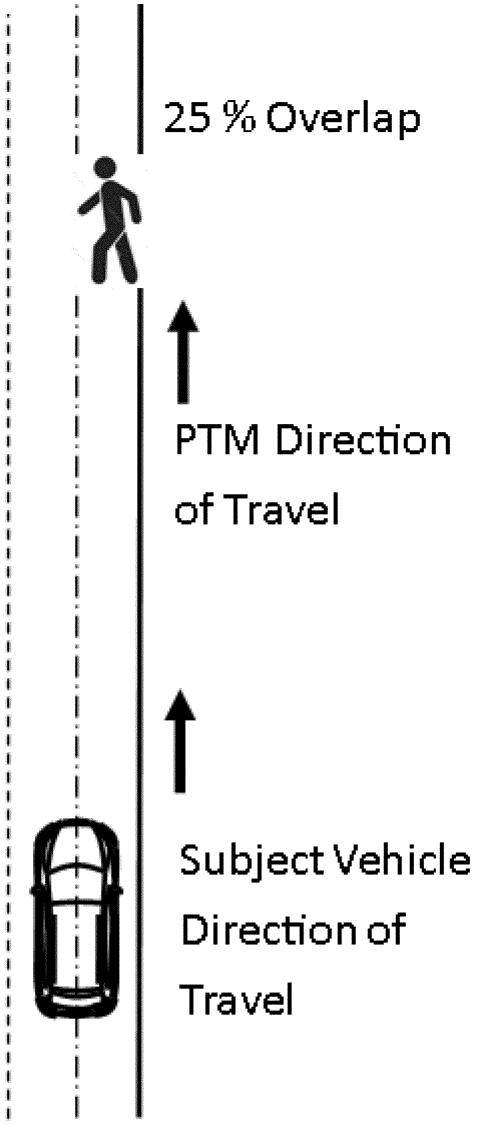


Figure 8 to § 571.127—Steel Trench Plate

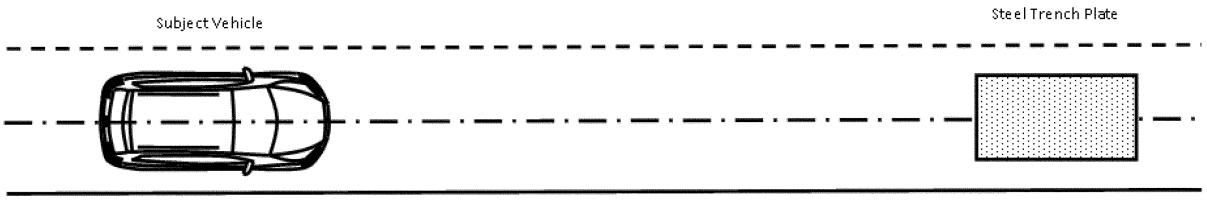
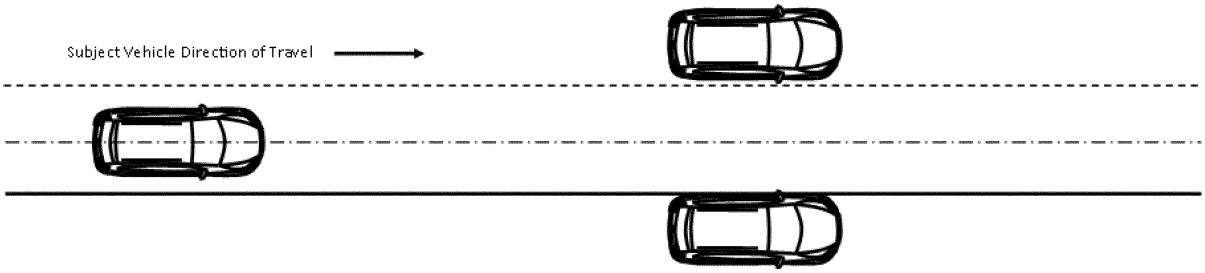


Figure 9 to § 571.127—Pass-through



BILLING CODE 4910–59–C

PART 595—MAKE INOPERATIVE EXEMPTIONS

■ 4. The authority citation for part 595 continues to read as follows:

Authority: 49 U.S.C. 322, 30111, 30115, 30117, 30122 and 30166; delegation of authority at 49 CFR 1.95.

■ 5. Amend § 595.4 by adding the definition of ''Manufacturer'' in alphabetical order to read as follows:

§ 595.4 Definitions.

* * * * *

Manufacturer is defined as it is in 49 U.S.C. 30102(a).

* * * * *

■ 6. Add subpart D to read as follows:

Subpart D—Modifications to Law Enforcement Vehicles

§ 595.9 Automatic emergency braking.

A manufacturer, dealer, or motor vehicle repair business that modifies a vehicle owned by a law enforcement agency to provide a means to temporarily deactivate an AEB system is exempted from the ''make inoperative'' prohibition in 49 U.S.C. 30122 to the extent that such modification affects the motor vehicle's compliance with 49 CFR 571.127, S5.4.2. Modifications that would take a vehicle out of compliance with any other Federal motor vehicle safety standards, or portions thereof, are not covered by this exemption.

■ 7. Add part 596 to read as follows.

PART 596—AUTOMATIC EMERGENCY BRAKING TEST DEVICES

Subpart A—General

Sec.
596.1 Scope.
596.2 Purpose.
596.3 Application.
596.4 Definitions.
596.5 Matter incorporated by reference.

Subpart B—Pedestrian Test Devices

596.7 Specifications for pedestrian test devices.
596.8 [Reserved]

Subpart C—Vehicle Test Device

596.9 General description.
596.10 Specifications for the vehicle test device.

Authority: 49 U.S.C. 322, 30111, 30115, 30117 and 30166; delegation of authority at 49 CFR 1.95.

Subpart A—General

§ 596.1 Scope.

This part describes the test devices to be used for compliance testing of motor vehicles with motor vehicle safety standards for automatic emergency braking.

§ 596.2 Purpose.

The design and performance criteria specified in this part are intended to describe devices with sufficient precision such that testing performed with these test devices will produce repetitive and correlative results under similar test conditions to reflect adequately the automatic emergency braking performance of a motor vehicle.

§ 596.3 Application.

This part does not in itself impose duties or liabilities on any person. It is a description of tools that are used in compliance tests to measure the performance of automatic emergency braking systems required by the safety standards that refer to these tools. This part is designed to be referenced by, and become part of, the test procedures specified in motor vehicle safety standards, such as 49 CFR 571.127.

§ 596.4 Definitions.

All terms defined in section 30102 of the National Traffic and Motor Vehicle Safety Act (49 U.S.C. chapter 301, *et seq.*) are used in their statutory meaning.

Adult pedestrian test mannequin (APTM) means a test device with the appearance and radar cross section that simulates an adult pedestrian for the purpose of testing automatic emergency brake system performance.

Child pedestrian test mannequin (CPTM) means a test device with the appearance and radar cross section that stimulates a child pedestrian for the purpose of testing automatic emergency brake system performance.

Pedestrian test device(s) means an adult pedestrian test mannequin and/or a child pedestrian test mannequin.

Pedestrian test mannequin carrier means a movable platform on which an adult pedestrian test mannequin or child pedestrian test mannequin may be attached during compliance testing.

Vehicle test device means a test device that simulates a passenger vehicle for the purpose of testing automatic emergency brake system performance.

Vehicle test device carrier means a movable platform on which a lead vehicle test device may be attached during compliance testing.

§ 596.5 Matter incorporated by reference.

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To enforce any edition other than that specified in this section, the National Highway Traffic Safety Administration (NHTSA) must publish notice of change in the **Federal Register** and the material must be available to the public. All approved material is available for inspection at NHTSA and at the National Archives and Records Administration (NARA). Contact NHTSA at: NHTSA Office of Technical Information Services, 1200 New Jersey Avenue SE, Washington, DC 20590; (202) 366–2588. For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations* or email *fr.inspection@nara.gov.* The material may be obtained from the source(s) in the following paragraph of this section.

(a) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, CP 56, CH–1211 Geneva 20, Switzerland; phone: + 41 22 749 01 11 fax: + 41 22 733 34 30; website: *https://www.iso.org/.*

(1) ISO 3668:2017(E), *Paints and varnishes—Visual comparison of colour of paints,* Third edition, 2017–05 (ISO 3668:2017); into § 596.7.

(2) ISO 19206–2:2018(E), *Road vehicles—Test devices for target vehicles, vulnerable road users and other objects, for assessment of active safety functions—Part 2: Requirements for pedestrian targets,* First edition, 2018–12 (ISO 19206–2:2018); into § 596.7.

(3) ISO 19206–3:2021(E), *Test devices for target vehicles, vulnerable road users and other objects, for assessment of active safety functions—Part 3: Requirements for passenger vehicle 3D targets,* First edition, 2021–05 (ISO 19206–3:2021); into § 596.10.

(4) ISO 19206–4:2020(E), *Test devices for target vehicles, vulnerable road users and other objects, for assessment of active safety functions –Part 4: Requirements for bicyclist targets,* First edition, 2020–11 (ISO 19206–4:2020); into § 596.7.

(b) [Reserved]

Subpart B—Pedestrian Test Devices

§ 596.7 Specifications for pedestrian test devices.

(a) *Explanation of usage.* The words ''recommended,'' ''should,'' ''can be,'' or ''should be'' appearing in sections of ISO 19206–2:2018 (incorporated by reference, see § 596.5), referenced in this section, are read as setting forth specifications that are used.

(b) *Explanation of usage.* The words ''may be,'' or ''either'' used in connection with a set of items appearing in sections of ISO 19206–2:2018 (incorporated by reference, see § 596.5), referenced in this section, are read as setting forth the totality of items, any one of which may be selected by NHTSA for testing.

(c) *Specifications for the pedestrian test devices*—(1) *General description.* The adult pedestrian test mannequin (APTM) provides a sensor representation of a 50th percentile adult male and consist of a head, torso, two arms and hands, and two legs and feet. The child pedestrian test mannequin (CPTM) provides a sensor representation of a 6- to 7-year-old child and consists of a head, torso, two arms and hands, and two legs and feet. The arms of the APTM and CPTM are posable, but do not move during testing. The legs of the APTM and CPTM articulate and are synchronized to the forward motion of the mannequin.

(2) *Dimensions and posture.* The APTM has basic body dimensions and proportions specified in Annex A, table A.1 in ISO 19206–2:2018 (incorporated by reference, see § 596.5). The CPTM has basic body dimensions and proportions specified in Annex A, table A.1 in ISO 19206–2:2018 (incorporated by reference, see § 596.5).

(3) *Visual properties*—(i) *Head.* The head has a visible hairline silhouette by printed graphic. The hair is black as defined in Annex B table B.2 of ISO 19206–4:2020, as tested in accordance with ISO 3668:2017 (both incorporated by reference, see § 596.5).

(ii) *Face.* The head does not have any facial features (*i.e.,* eyes, nose, mouth, and ears).

(iii) *Skin.* The face, neck and hands have a skin colored as defined Annex B, table B.2 of ISO 19206–4:2020 (incorporated by reference, see § 596.5).

(iv) *Torso and arms.* The torso and arms are black as defined in Annex B table B.2 of ISO 19206–4:2020, as tested in accordance with ISO 3668:2017 (both incorporated by reference, see § 596.5).

(v) *Legs.* The legs are blue as defined in Annex B table B.2 of ISO 19206–4:2020, as tested in accordance with ISO 3668:2017 (both incorporated by reference, see § 596.5).

(vi) *Feet.* The feet are black as defined in Annex B table B.2 of ISO 19206–4:2020, as tested in accordance with ISO 3668:2017 (both incorporated by reference, see § 596.5).

(4) *Infrared properties.* The surface of the entire APTM or CPTM are within the reflectivity ranges specified in Annex B section B.2.2 of ISO 19206–2:2018, as illustrated in Annex B, figure B.2 (incorporated by reference, see § 596.5).

(5) *Radar properties.* The radar reflectivity characteristics of the pedestrian test device approximates that of a pedestrian of the same size when approached from the side or from behind.

(6) *Radar cross section measurements.* The radar cross section measurements of the APTM and the CPTM is within the upper and lower boundaries shown in Annex B, section B.3, figure B.6 of ISO 19206–2:2018 when tested in accordance with the measure procedure in Annex C, section C.3, Scenario 2 Fixed Angle Scans of ISO 19206–3:2021 with a measurement range of 4m to 40m (incorporated by reference, see § 596.5).

(7) *Posture.* The pedestrian test device has arms that are posable and remain posed during testing. The pedestrian test device is equipped with moving legs consistent with standard gait phases specified in Section 5.6 of ISO 19206–2:2018 (incorporated by reference, see § 596.5).

(8) *Articulation properties.* The legs of the pedestrian test device are in accordance with, and as described in, Annex D, section D.2 and illustrated in Figures D.1, D.2, and D.3 of ISO 19206–2:2018 (incorporated by reference, see § 596.6).

§ 596.8 [Reserved]

Subpart C—Vehicle Test Device

§ 596.9 General description.

(a) The vehicle test device provides a sensor representation of a passenger motor vehicle.

(b) The rear view of the vehicle test device contains representations of the vehicle silhouette, a rear window, a high-mounted stop lamp, two taillamps, a rear license plate, two rear reflex reflectors, and two tires.

§ 596.10 Specifications for the vehicle test device.

(a) *Explanation of usage.* The words ''recommended,'' ''should,'' ''can be,'' or ''should be'' appearing in sections of ISO 19206–3:2021 (incorporated by reference, see § 596.5), referenced in this section, are read as setting forth specifications that are used.

(b) *Explanation of usage.* The words ''may be,'' or ''either,'' used in connection with a set of items appearing in sections of ISO 19206–3:2021 (incorporated by reference, see § 596.5), referenced in this section, are read as setting forth the totality of items, any one of which may be selected by NHTSA for testing.

(c) *Dimensional specifications.* (1) The rear silhouette and the rear window are symmetrical about a shared vertical centerline.

(2) Representations of the taillamps, rear reflex reflectors, and tires are symmetrical about the surrogate's centerline.

(3) The license plate representation has a width of 300 ± 15 mm and a height of 150 ± 15 mm and mounted with a license plate holder angle within the range described in 49 CFR 571.108, S6.6.3.1.

(4) The vehicle test device representations are located within the minimum and maximum measurement values specified in columns 3 and 4 of Tables A.4 of ISO 19206–3:2021 Annex A (incorporated by reference, see § 596.5). The tire representations are located within the minimum and maximum measurement values specified in columns 3 and 4 of Tables A.3 of ISO 19206–3:2021 Annex A (incorporated by reference, see § 596.5). The terms ''rear light'' means ''taillamp,'' ''retroreflector'' means ''reflex reflector,'' and ''high centre taillight'' means ''high-mounted stop lamp.''

(d) *Visual and near infrared specification.* (1) The vehicle test device rear representation colors are within the ranges specified in Tables B.2 and B.3 of ISO 19206–3:2021 Annex B (incorporated by reference, see § 596.5).

(2) The rear representation infrared properties of the vehicle test device are within the ranges specified in Table B.1 of ISO 19206–3:2021 Annex B (incorporated by reference, see § 596.5) for wavelengths of 850 to 950 nm when measured according to the calibration and measurement setup specified in paragraph B.3 of ISO 19206–3:2021 Annex B (incorporated by reference, see § 596.5).

(3) The vehicle test device rear reflex reflectors, and at least 50 cm^2 of the taillamp representations are grade DOT–C2 reflective sheeting as specified in 49 CFR 571.108, S8.2.

(e) *Radar reflectivity specifications.* (1) The radar cross section of the vehicle test device is measured with it attached to the carrier (robotic platform). The radar reflectivity of the carrier platform is less than 0 dBm^2 for a viewing angle of 180 degrees and over a range of 5 to 100 m when measured according to the radar measurement procedure specified in Section C.3 of ISO 19206–3:2021 Annex C (incorporated by reference, see § 596.5) for fixed-angle scans.

(2) The rear bumper area as shown in Table C.1 of ISO 19206–3:2021 Annex C (incorporated by reference, see § 596.5) contributes to the target radar cross section.

(3) The radar cross section is assessed using radar sensor that operates at 76 to 81 GHz and has a range of at least 5 to 100 m, a range gate length smaller than 0.6m, a horizontal field of view of 10 degrees or more (–3dB amplitude limit), and an elevation field of view of 5 degrees or more (–3dB amplitude).

(4) At least 92 percent of the filtered data points of the surrogate radar cross section for the fixed vehicle angle, variable range measurements are within the radar cross section boundaries defined in Section C.2.2.4 of ISO 19206–3:2021 Annex C (incorporated by reference, see § 596.5) for a viewing angle of 180 degrees when measured according to the radar measurement procedure specified in Section C.3 of ISO 19206–3:2021 Annex C (incorporated by reference, see § 596.5) for fixed-angle scans.

(5) Between 86 to 95 percent of the vehicle test device spatial radar cross section reflective power is with the primary reflection region defined in Section C.2.2.5 of ISO 19206–3:2021 Annex C (incorporated by reference, see § 596.5) when measured according to the radar measurement procedure specified in Section C.3 of ISO 19206–3:2021 Annex C (incorporated by reference, see § 596.5) using the angle-penetration method.

Issued in Washington, DC, under authority delegated in 49 CFR 1.95 and 501.5.

Sophie Shulman,

Deputy Administrator.

[FR Doc. 2024–09054 Filed 5–8–24; 8:45 am]

BILLING CODE 4910–59–P

FEDERAL REGISTER

Vol. 89 Thursday,

No. 91 May 9, 2024

Part III

Environmental Protection Agency

40 CFR Part 60

New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2023–0072; FRL–8536–01–OAR]

RIN 2060–AV09

New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing multiple actions under section 111 of the Clean Air Act (CAA) addressing greenhouse gas (GHG) emissions from fossil fuel-fired electric generating units (EGUs). First, the EPA is finalizing the repeal of the Affordable Clean Energy (ACE) Rule. Second, the EPA is finalizing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Third, the EPA is finalizing revisions to the New Source Performance Standards (NSPS) for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Fourth, the EPA is finalizing revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The EPA is not finalizing emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines at this time; instead, the EPA intends to take further action on the proposed emission guidelines at a later date.

DATES: This final rule is effective on July 8, 2024. The incorporation by reference of certain publications listed in the rules is approved by the Director of the Federal Register as of July 8, 2024. The incorporation by reference of certain other materials listed in the rule was approved by the Director of the Federal Register as of October 23, 2015.

ADDRESSES: The EPA has established a docket for these actions under Docket ID No. EPA–HQ–OAR–2023–0072. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed, some information is not publicly available, *e.g.,* Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: Lisa Thompson (she/her), Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, 109 T.W. Alexander Drive, P.O. Box 12055, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5158; and email address: *thompson.lisa@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble acronyms and abbreviations. Throughout this document the use of ''we,'' ''us,'' or ''our'' is intended to refer to the EPA. The EPA uses multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACE Affordable Clean Energy rule
BSER best system of emissions reduction
Btu British thermal unit
CAA Clean Air Act
CBI Confidential Business Information
CCS carbon capture and sequestration/storage
CCUS carbon capture, utilization, and sequestration/storage
CO_2 carbon dioxide
DER distributed energy resources
DOE Department of Energy
EEA energy emergency alert
EGU electric generating unit
EIA Energy Information Administration
EJ environmental justice
E.O. Executive Order
EPA Environmental Protection Agency
FEED front-end engineering and design
FGD flue gas desulfurization
FR Federal Register
GHG greenhouse gas
GW gigawatt
GWh gigawatt-hour
HAP hazardous air pollutant
HRSG heat recovery steam generator
IIJA Infrastructure Investment and Jobs Act
IRC Internal Revenue Code
kg kilogram
kWh kilowatt-hour
LCOE levelized cost of electricity
LNG liquefied natural gas
MATS Mercury and Air Toxics Standards
MMBtu/h million British thermal units per hour
MMT CO_2e million metric tons of carbon dioxide equivalent
MW megawatt
MWh megawatt-hour
NAAQS National Ambient Air Quality Standards
NESHAP National Emission Standards for Hazardous Air Pollutants
NGCC natural gas combined cycle
NO_X nitrogen oxides
NSPS new source performance standards
NSR New Source Review
PM particulate matter
$PM_{2.5}$ fine particulate matter
RIA regulatory impact analysis
TSD technical support document
U.S. United States

Organization of this document. The information in this preamble is organized as follows:

I. Executive Summary
A. Climate Change and Fossil Fuel-Fired EGUs
B. Recent Developments in Emissions Controls and the Electric Power Sector
C. Summary of the Principal Provisions of These Regulatory Actions
D. Grid Reliability Considerations
E. Environmental Justice Considerations
F. Energy Workers and Communities
G. Key Changes From Proposal
II. General Information
A. Action Applicability
B. Where To Get a Copy of This Document and Other Related Information
III. Climate Change Impacts
IV. Recent Developments in Emissions Controls and the Electric Power Sector
A. Background
B. GHG Emissions From Fossil Fuel-Fired EGUs
C. Recent Developments in Emissions Control
D. The Electric Power Sector: Trends and Current Structure
E. The Legislative, Market, and State Law Context
F. Future Projections of Power Sector Trends
V. Statutory Background and Regulatory History for CAA Section 111
A. Statutory Authority To Regulate GHGs From EGUs Under CAA Section 111
B. History of EPA Regulation of Greenhouse Gases From Electricity Generating Units Under CAA Section 111 and Caselaw
C. Detailed Discussion of CAA Section 111 Requirements

VI. ACE Rule Repeal
A. Summary of Selected Features of the ACE Rule
B. Developments Undermining ACE Rule's Projected Emission Reductions
C. Developments Showing That Other Technologies Are the BSER for This Source Category
D. Insufficiently Precise Degree of Emission Limitation Achievable From Application of the BSER
E. Withdrawal of Proposed NSR Revisions
VII. Regulatory Approach for Existing Fossil Fuel-Fired Steam Generating Units
A. Overview
B. Applicability Requirements and Fossil Fuel-Type Definitions for Subcategories of Steam Generating Units
C. Rationale for the BSER for Coal-Fired Steam Generating Units
D. Rationale for the BSER for Natural Gas-Fired and Oil-Fired Steam Generating Units
E. Additional Comments Received on the Emission Guidelines for Existing Steam Generating Units and Responses
F. Regulatory Requirement To Review Emission Guidelines for Coal-Fired Units
VIII. Requirements for New and Reconstructed Stationary Combustion Turbine EGUs and Rationale for Requirements
A. Overview
B. Combustion Turbine Technology
C. Overview of Regulation of Stationary Combustion Turbines for GHGs
D. Eight-Year Review of NSPS
E. Applicability Requirements and Subcategorization
F. Determination of the Best System of Emission Reduction (BSER) for New and Reconstructed Stationary Combustion Turbines
G. Standards of Performance
H. Reconstructed Stationary Combustion Turbines
I. Modified Stationary Combustion Turbines
J. Startup, Shutdown, and Malfunction
K. Testing and Monitoring Requirements
L. Recordkeeping and Reporting Requirements
M. Compliance Dates
N. Compliance Date Extension
IX. Requirements for New, Modified, and Reconstructed Fossil Fuel-Fired Steam Generating Units
A. 2018 NSPS Proposal Withdrawal
B. Additional Amendments
C. Eight-Year Review of NSPS for Fossil Fuel-Fired Steam Generating Units
D. Projects Under Development
X. State Plans for Emission Guidelines for Existing Fossil Fuel-Fired EGUs
A. Overview
B. Requirement for State Plans To Maintain Stringency of the EPA's BSER Determination
C. Establishing Standards of Performance
D. Compliance Flexibilities
E. State Plan Components and Submission
XI. Implications for Other CAA Programs
A. New Source Review Program
B. Title V Program
XII. Summary of Cost, Environmental, and Economic Impacts
A. Air Quality Impacts
B. Compliance Cost Impacts
C. Economic and Energy Impacts
D. Benefits
E. Net Benefits
F. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement
G. Grid Reliability Considerations and Reliability-Related Mechanisms
XIII. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review
B. Paperwork Reduction Act (PRA)
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act of 1995 (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks Populations and Low-Income Populations
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All
K. Congressional Review Act (CRA)
XIV. Statutory Authority

I. Executive Summary

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare.[1] Since that time, the evidence of the harms posed by GHG emissions has only grown, and Americans experience the destructive and worsening effects of climate change every day.[2] Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2021.[3] At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources is available to the power sector—including carbon capture and sequestration/storage (CCS), co-firing with less GHG-intensive fuels, and more efficient generation. Congress has also acted to provide funding and other incentives to encourage the deployment of various technologies, including CCS, to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is finalizing several actions under section 111 of the Clean Air Act (CAA) to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing emission guidelines and new source performance standards (NSPS) that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of CAA section 111, the final NSPS and emission guidelines reflect the application of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

Specifically, the EPA is first finalizing the repeal of the Affordable Clean Energy (ACE) Rule. Second, the EPA is finalizing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Third, the EPA is finalizing revisions to the NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. Fourth, the EPA is finalizing revisions to the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. The EPA is not finalizing emission guidelines for GHG emissions from existing fossil fuel-fired combustion turbines at this time and plans to expeditiously issue an additional proposal that more comprehensively addresses GHG emissions from this portion of the fleet. The EPA acknowledges that the share of GHG emissions from existing fossil fuel-fired combustion turbines has been growing and is projected to continue to do so, particularly as emissions from other portions of the fleet decline, and that it is vital to regulate the GHG emissions from these sources consistent with CAA section 111.

These final actions ensure that the new and existing fossil fuel-fired EGUs that are subject to these rules reduce their GHG emissions in a manner that is cost-effective and improves the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These standards and emission guidelines will significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and

[1] 74 FR 66496 (December 15, 2009).

[2] The 5th National Climate Assessment (NCA5) states that the effects of human-caused climate change are already far-reaching and worsening across every region of the United States and that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends.

[3] *https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.*

welfare. Further, the EPA has designed these standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

A. Climate Change and Fossil Fuel-Fired EGUs

These final actions reduce the emissions of GHGs from new and existing fossil fuel-fired EGUs. The increasing concentrations of GHGs in the atmosphere are, and have been, warming the planet, resulting in serious and life-threatening environmental and human health impacts. The increased concentrations of GHGs in the atmosphere and the resulting warming have led to more frequent and more intense heat waves and extreme weather events, rising sea levels, and retreating snow and ice, all of which are occurring at a pace and scale that threaten human health and welfare.

Fossil fuel-fired EGUs that are uncontrolled for GHGs are one of the biggest domestic sources of GHG emissions. At the same time, there are technologies available (including technologies that can be applied to fossil fuel-fired power plants) to significantly reduce emissions of GHGs from the power sector. Low- and zero-GHG electricity are also key enabling technologies to significantly reduce GHG emissions in almost every other sector of the economy.

In 2021, the power sector was the largest stationary source of GHGs in the United States, emitting 25 percent of overall domestic emissions.[4] In 2021, existing fossil fuel-fired steam generating units accounted for 65 percent of the GHG emissions from the sector, but only accounted for 23 percent of the total electricity generation.

Because of its outsized contributions to overall emissions, reducing emissions from the power sector is essential to addressing the challenge of climate change—and sources in the power sector also have many available options for reducing their climate-destabilizing emissions. Particularly relevant to these actions are several key technologies (CCS and co-firing of lower-GHG fuels) that allow fossil fuel-fired steam generating EGUs and stationary combustion turbines to provide power while emitting significantly lower GHG emissions. Moreover, with the increased electrification of other GHG-emitting sectors of the economy, such as personal vehicles, heavy-duty trucks, and the heating and cooling of buildings, reducing GHG emissions from these affected sources can also help reduce power sector pollution that might otherwise result from the electrification of other sectors of the economy.

B. Recent Developments in Emissions Controls and the Electric Power Sector

Several recent developments concerning emissions controls are relevant for the EPA's determination of the BSER for existing coal-fired steam generating EGUs and new natural gas-fired stationary combustion turbines. These include lower costs and continued improvements in CCS technology, alongside Federal tax incentives that allow companies to largely offset the cost of CCS. Well-established trends in the sector further inform where using such technologies is cost effective and feasible, and form part of the basis for the EPA's determination of the BSER.

In recent years, the cost of CCS has declined in part because of process improvements learned from earlier deployments and other advances in the technology. In addition, the Inflation Reduction Act (IRA), enacted in 2022, extended and significantly increased the tax credit for carbon dioxide (CO_2) sequestration under Internal Revenue Code (IRC) section 45Q. The provision of tax credits in the IRA, combined with the funding included in the Infrastructure Investment and Jobs Act (IIJA), enacted in 2021, incentivize and facilitate the deployment of CCS and other GHG emission control technologies. As explained later in this preamble, these developments support the EPA's conclusion that CCS is the BSER for certain subcategories of new and existing EGUs because it is an adequately demonstrated and available control technology that significantly reduces emissions of dangerous pollution and because the costs of its installation and operation are reasonable. Some companies have already made plans to install CCS on their units independent of the EPA's regulations.

Well documented trends in the power sector also influence the EPA's determination of the BSER. In particular, CCS entails significant capital expenditures and is only cost-reasonable for units that will operate enough to defray those capital costs. At the same time, many utilities and power generating companies have recently announced plans to accelerate changing the mix of their generating assets. The IIJA and IRA, state legislation, technology advancements, market forces, consumer demand, and the advanced age of much of the existing fossil fuel-fired generating fleet are collectively leading to, in most cases, decreased use of the fossil fuel-fired units that are the subjects of these final actions. From 2010 through 2022, fossil fuel-fired generation declined from approximately 72 percent of total net generation to approximately 60 percent, with generation from coal-fired sources dropping from 49 percent to 20 percent of net generation during this period.[5] These trends are expected to continue and are relevant to determining where capital-intensive technologies, like CCS, may be feasibly and cost-reasonably deployed to reduce emissions.

Congress has taken other recent actions to drive the reduction of GHG emissions from the power sector. As noted earlier, Congress enacted IRC section 45Q in section 115 of the Energy Improvement and Extension Act of 2008 to provide a tax credit for the sequestration of CO_2. Congress significantly amended IRC section 45Q in the Bipartisan Budget Act of 2018, and more recently in the IRA, to make this tax incentive more generous and effective in spurring long-term deployment of CCS. In addition, the IIJA provided more than $65 billion for infrastructure investments and upgrades for transmission capacity, pipelines, and low-carbon fuels.[6] Further, the Creating Helpful Incentives to Produce Semiconductors and Science Act (CHIPS Act) authorized billions more in funding for development of low- and non-GHG emitting energy technologies that could provide additional low-cost options for power companies to reduce overall GHG emissions.[7] As discussed in greater detail in section IV.E.1 of this preamble, the IRA, the IIJA, and CHIPS contain numerous other provisions encouraging companies to reduce their GHGs.

C. Summary of the Principal Provisions of These Regulatory Actions

These final actions include the repeal of the ACE Rule, BSER determinations and emission guidelines for existing fossil fuel-fired steam generating units, and BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines and modified fossil fuel-fired steam generating units.

[4] *https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.*

[5] U.S. Energy Information Administration (EIA). Electric Power Annual. 2010 and 2022. *https://www.eia.gov/electricity/annual/html/epa_03_01_a.html.*

[6] *https://www.congress.gov/bill/117th-congress/house-bill/3684.*

[7] *https://www.congress.gov/bill/117th-congress/house-bill/4346.*

The EPA is taking these actions consistent with its authority under CAA section 111. Under CAA section 111, once the EPA has identified a source category that contributes significantly to dangerous air pollution, it proceeds to regulate new sources and, for GHGs and certain other air pollutants, existing sources. The central requirement is that the EPA must determine the ''best system of emission reduction . . . adequately demonstrated,'' taking into account the cost of the reductions, non-air quality health and environmental impacts, and energy requirements.[8] The EPA may determine that different sets of sources have different characteristics relevant for determining the BSER and may subcategorize sources accordingly.

Once it identifies the BSER, the EPA must determine the ''degree of emission limitation'' achievable by application of the BSER. For new sources, the EPA establishes the standard of performance with which the sources must comply, which is a standard for emissions that reflects the degree of emission limitation. For existing sources, the EPA includes the information it has developed concerning the BSER and associated degree of emission limitation in emission guidelines and directs the states to adopt state plans that contain standards of performance that are consistent with the emission guidelines.

Since the early 1970s, the EPA has promulgated regulations under CAA section 111 for more than 60 source categories, which has established a robust set of regulatory precedents that has informed the development of these final actions. During this period, the courts, primarily the U.S. Court of Appeals for the D.C. Circuit and the Supreme Court, have developed a body of caselaw interpreting CAA section 111. As the Supreme Court has recognized, the EPA has typically (and does so in these actions) determined the BSER to be ''measures that improve the pollution performance of individual sources,'' such as add-on controls and clean fuels. *West Virginia* v. *EPA,* 597 U.S. 697, 734 (2022). For present purposes, several of a BSER's key features include that it must reduce emissions, be based on ''adequately demonstrated'' technology, and have a reasonable cost of control. The case law interpreting section 111 has also recognized that the BSER can be forward-looking in nature and take into account anticipated improvements in control technologies. For example, the EPA may determine a control to be ''adequately demonstrated'' even if it is new and not yet in widespread commercial use, and, further, that the EPA may reasonably project the development of a control system at a future time and establish requirements that take effect at that time. Further, the most relevant costs under CAA section 111 are the costs to the regulated facility. The actions that the EPA is finalizing are consistent with the requirements of CAA section 111 and its regulatory history and caselaw, which is discussed in further detail in section V of this preamble.

[8] CAA section 111(a)(1).

1. Repeal of ACE Rule

The EPA is finalizing its proposed repeal of the existing ACE Rule emission guidelines. First, as a policy matter, the EPA concludes that the suite of heat rate improvements (HRI) that was identified in the ACE Rule as the BSER is not an appropriate BSER for existing coal-fired EGUs. Second, the ACE Rule rejected CCS and natural gas co-firing as the BSER for reasons that no longer apply. Third, the EPA concludes that the ACE Rule conflicted with CAA section 111 and the EPA's implementing regulations because it did not provide sufficient specificity as to the BSER the EPA had identified or the ''degree of emission limitation achievable though application of the [BSER].''

Also, the EPA is withdrawing the proposed revisions to the New Source Review (NSR) regulations that were included the ACE Rule proposal (83 FR 44773–83; August 31, 2018).

2. Emission Guidelines for Existing Fossil Fuel-Fired Steam Generating Units

The EPA is finalizing CCS with 90 percent capture as BSER for existing coal-fired steam generating units. These units have a presumptive standard[9] of an 88.4 percent reduction in annual emission rate, with a compliance deadline of January 1, 2032. As explained in detail below, CCS is an adequately demonstrated technology that achieves significant emissions reduction and is cost-reasonable, taking into account the declining costs of the technology and a substantial tax credit available to sources. In recognition of the significant capital expenditures involved in deploying CCS technology and the fact that 45 percent of regulated units already have announced retirement dates, the EPA is finalizing a separate subcategory for existing coal-fired steam generating units that demonstrate that they plan to permanently cease operation before January 1, 2039. The BSER for this subcategory is co-firing with natural gas, at a level of 40 percent of the unit's annual heat input. These units have a presumptive standard of 16 percent reduction in annual emission rate corresponding to this BSER, with a compliance deadline of January 1, 2030.

The EPA is finalizing an applicability exemption for existing coal-fired steam EGUs demonstrating that they plan to permanently cease operation prior to January 1, 2032, based on the Agency's determination that units retiring before this date generally do not have cost-reasonable options for improving their GHG emissions performance. Sources that demonstrate they will permanently cease operation before this applicability deadline will not be subject to these emission guidelines. Further, the EPA is not finalizing the proposed imminent-term or near-term subcategories.

The EPA is finalizing the proposed structure of the subcategory definitions for natural gas- and oil-fired steam generating units. The EPA is also finalizing routine methods of operation and maintenance as the BSER for intermediate load and base load natural gas- and oil-fired steam generating units. Furthermore, the EPA is finalizing presumptive standards for natural gas- and oil-fired steam generating units that are slightly higher than at proposal: base load sources (those with annual capacity factors greater than 45 percent) have a presumptive standard of 1,400 lb CO_2/MWh-gross, and intermediate load sources (those with annual capacity factors greater than 8 percent and less than or equal to 45 percent) have a presumptive standard of 1,600 lb CO_2/MWh-gross. For low load (those with annual capacity factors less than 8 percent), the EPA is finalizing a uniform fuels BSER and a presumptive input-based standard of 170 lb CO_2/MMBtu for oil-fired sources and a presumptive standard of 130 lb CO_2/MMBtu for natural gas-fired sources.

3. Standards of Performance for New and Reconstructed Fossil Fuel-Fired Combustion Turbines

The EPA is finalizing emission standards for three subcategories of combustion turbines—base load, intermediate load, and low load. The BSER for base load combustion turbines includes two components to be implemented initially in two phases. The first component of the BSER for base load combustion turbines is highly efficient generation (based on the emission rates that the best performing

[9] Presumptive standards of performance are discussed in detail in section X of the preamble. While states establish standards of performance for sources, the EPA provides presumptively approvable standards of performance based on the degree of emission limitation achievable through application of the BSER for each subcategory.

units are achieving) and the second component for base load combustion turbines is utilization of CCS with 90 percent capture. Recognizing the lead time that is necessary for new base load combustion turbines to plan for and install the second component of the BSER (*i.e.,* 90 percent CCS), including the time that is needed to deploy the associated infrastructure (CO_2 pipelines, storage sites, *etc.*), the EPA is finalizing a second phase compliance deadline of January 1, 2032, for this second component of the standard.

The EPA has identified highly efficient simple cycle generation as the BSER for intermediate load combustion turbines. For low load combustion turbines, the EPA is finalizing its proposed determination that the BSER is the use of lower-emitting fuels.

4. New, Modified, and Reconstructed Fossil Fuel-Fired Steam Generating Units

The EPA is finalizing revisions of the standards of performance for coal-fired steam generating units that undertake a large modification (*i.e.,* a modification that increases its hourly emission rate by more than 10 percent) to mirror the emission guidelines for existing coal-fired steam generators. This reflects the EPA's determination that such modified sources are capable of meeting the same presumptive standards that the EPA is finalizing for existing steam EGUs. Further, this revised standard for modified coal-fired steam EGUs will avoid creating an unjustified disparity between emission control obligations for modified and existing coal-fired steam EGUs.

The EPA did not propose, and we are not finalizing, any review or revision of the 2015 standard for large modifications of oil- or gas-fired steam generating units because we are not aware of any existing oil- or gas-fired steam generating EGUs that have undertaken such modifications or have plans to do so, and, unlike an existing coal-fired steam generating EGUs, existing oil- or gas-fired steam units have no incentive to undertake such a modification to avoid the requirements we are including in this final rule for existing oil- or gas-fired steam generating units.

As discussed in the proposal preamble, the EPA is not revising the NSPS for newly constructed or reconstructed fossil fuel-fired steam electric generating units (EGU) at this time because the EPA anticipates that few, if any, such units will be constructed or reconstructed in the foreseeable future. However, the EPA has recently become aware that a new coal-fired power plant is under consideration in Alaska. Accordingly, the EPA is not, at this time, finalizing its proposal not to review the 2015 NSPS, and, instead, will continue to consider whether to review the 2015 NSPS. As developments warrant, the EPA will determine either to conduct a review, and propose revised standards of performance, or not conduct a review.

Also, in this final action, the EPA is withdrawing the 2018 proposed amendments [10] to the NSPS for GHG emissions from coal-fired EGUs.

5. Severability

This final action is composed of four independent rules: the repeal of the ACE rule; GHG emission guidelines for existing fossil fuel-fired steam generating units; NSPS for GHG emissions from new and reconstructed fossil fuel-fired combustion turbines; and revisions to the standards of performance for new, modified, and reconstructed fossil fuel-fired steam generating units. The EPA could have finalized each of these rules in separate **Federal Register** notices as separate final actions. The Agency decided to include these four independent rules in a single **Federal Register** notice for administrative ease because they all relate to climate pollution from the fossil fuel-fired electric generating units source category. Accordingly, despite grouping these rules into one single **Federal Register** notice, the EPA intends that each of these rules described in sections I.C.1 through I.C.4 is severable from the other.

In addition, each rule is severable as a practical matter. For example, the EPA would repeal the ACE Rule separate and apart from finalizing new standards for these sources as explained herein. Moreover, the BSER and associated emission guidelines for existing fossil fuel-fired steam generating units are independent of and would have been the same regardless of whether the EPA finalized the other parts of this rule. In determining the BSER for existing fossil fuel-fired steam generating units, the EPA considered only the technologies available to reduce GHG emissions at those sources and did not take into consideration the technologies or standards of performance for new fossil fuel-fired combustion turbines. The same is true for the Agency's evaluation and determination of the BSER and associated standards of performance for new fossil fuel-fired combustion turbines. The EPA identified the BSER and established the standards of performance by examining the controls that were available for these units. That analysis can stand alone and apart from the EPA's separate analysis for existing fossil fuel-fired steam generating units. Though the record evidence (including, for example, modeling results) often addresses the availability, performance, and expected implementation of the technologies at both existing fossil fuel-fired steam generating units and new fossil fuel-fired combustion turbines in the same record documents, the evidence for each evaluation stands on its own, and is independently sufficient to support each of the final BSERs.

In addition, within section I.C.1, the final action to repeal the ACE Rule is severable from the withdrawal of the NSR revisions that were proposed in parallel with the ACE Rule proposal. Within the group of actions for existing fossil fuel-fired steam generating units in section I.C.2, the requirements for each subcategory of existing sources are severable from the requirements for each other subcategory of existing sources. For example, if a court were to invalidate the BSER and associated emission standard for units in the medium-term subcategory, the BSER and associated emission standard for units in the long-term subcategory could function sensibly because the effectiveness of the BSER for each subcategory is not dependent on the effectiveness of the BSER for other subcategories. Within the group of actions for new and reconstructed fossil fuel-fired combustion turbines in section I.C.3, the following actions are severable: the requirements for each subcategory of new and reconstructed turbines are severable from the requirements for each other subcategory; and within the subcategory for base load turbines, the requirements for each of the two components are severable from the requirements for the other component. Each of these standards can function sensibly without the others. For example, the BSER for low load, intermediate load, and base load subcategories is based on the technologies the EPA determined met the statutory standards for those subcategories and are independent from each other. And in the base load subcategory units may practically be constructed using the most efficient technology without then installing CCS and likewise may install CCS on a turbine system that was not constructed with the most efficient technology. Within the group of actions for new, modified, and reconstructed fossil fuel-fired steam generating units in section I.C.4, the revisions of the standards of performance for coal-fired steam

[10] See 83 FR 65424, December 20, 2018.

generators that undertake a large modification are severable from the withdrawal of the 2018 proposal to revise the NSPS for emissions of GHG from EGUs. Each of the actions in these final rules that the EPA has identified as severable is functionally independent—*i.e.,* may operate in practice independently of the other actions.

In addition, while the EPA is finalizing this rule at the same time as other final rules regulating different types of pollution from EGUs—specifically the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (FR 2024–09815, EPA–HQ–OW–2009–0819; FRL–8794–02–OW); National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (FR 2024–09148, EPA–HQ–OAR–2018–0794; FRL–6716.3–02–OAR); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments (FR 2024–09157, EPA–HQ–OLEM–2020–0107; FRL–7814–04–OLEM)—and has considered the interactions between and cumulative effects of these rules, each rule is based on different statutory authority, a different record, and is completely independent of the other rules.

D. Grid Reliability Considerations

The EPA is finalizing multiple adjustments to the proposed rules that ensure the requirements in these final actions can be implemented without compromising the ability of power companies, grid operators, and state and Federal energy regulators to maintain resource adequacy and grid reliability. In response to the May 2023 proposed rule, the EPA received extensive comments from balancing authorities, independent system operators and regional transmission organizations, state regulators, power companies, and other stakeholders on the need for the final rule to accommodate resource adequacy and grid reliability needs. The EPA also engaged with the balancing authorities that submitted comments to the docket, the staff and Commissioners of the Federal Energy Regulatory Commission (FERC), the Department of Energy (DOE), the North American Electric Reliability Corporation (NERC), and other expert entities during the course of this rulemaking. Finally, at the invitation of FERC, the EPA participated in FERC's Annual Reliability Technical Conference on November 9, 2023.

These final actions respond to this input and feedback in multiple ways, including through changes to the universe of affected sources, longer compliance timeframes for CCS implementation, and other compliance flexibilities, as well as articulation of the appropriate use of RULOF to address reliability issues during state plan development and in subsequent state plan revisions. In addition to these adjustments, the EPA is finalizing several programmatic mechanisms specifically designed to address reliability concerns raised by commenters. For existing fossil fuel-fired EGUs, a short-term reliability emergency mechanism is available for states to provide more flexibility by using an alternative emission limitation during acute operational emergencies when the grid might be temporarily under heavy strain. A similar short-term reliability emergency mechanism is also available to new sources. In addition, the EPA is creating an option for states to provide for a compliance date extension for existing sources of up to 1 year under certain circumstances for sources that are installing control technologies to comply with their standards of performance. Lastly, states may also provide, by inclusion in their state plans, a reliability assurance mechanism of up to 1 year that under limited circumstances would allow existing units that had planned to cease operating by a certain date to temporarily remain available to support reliability. Any extensions exceeding 1 year must be addressed through a state plan revision. In order to utilize this reliability pathway, there must be an adequate demonstration of need and certification by a reliability authority, and approval by the appropriate EPA Regional Administrator. The EPA plans to seek the advice of FERC for extension requests exceeding 6 months. Similarly, for new fossil fuel-fired combustion turbines, the EPA is creating a mechanism whereby baseload units may request a 1-year extension of their CCS compliance deadline under certain circumstances.

The EPA has evaluated the resource adequacy implications of these actions in the final technical support document (TSD), *Resource Adequacy Analysis,* and conducted capacity expansion modeling of the final rules in a manner that takes into account resource adequacy needs. The EPA finds that resource adequacy can be maintained with the final rules. The EPA modeled a scenario that complies with the final rules and that meets resource adequacy needs. The EPA also performed a variety of other sensitivity analyses looking at higher electricity demand (load growth) and impact of the EPA's additional regulatory actions affecting the power sector. These sensitivity analyses indicate that, in the context of higher demand and other pending power sector rules, the industry has available pathways to comply with this rule that respect NERC reliability considerations and constraints.

In addition, the EPA notes that significant planning and regulatory mechanisms exist to ensure that sufficient generation resources are available to maintain reliability. The EPA's consideration of reliability in this rulemaking has also been informed by consultation with the DOE under the auspices of the March 9, 2023, memorandum of understanding (MOU) [11] signed by the EPA Administrator and the Secretary of Energy, as well as by consultation with FERC expert staff. In these final actions, the EPA has included various flexibilities that allow power companies and grid operators to plan for achieving feasible and necessary reductions of GHGs from affected sources consistent with the EPA's statutory charge while ensuring that the rule will not interfere with systems operators' ability to ensure grid reliability.

A thorough description of how adjustments in the final rules address reliability issues, the EPA's outreach to balancing authorities, EPA's supplemental notice, as well as the introduction of mechanisms to address short- and long-term reliability needs is presented in section XII.F of this preamble.

E. Environmental Justice Considerations

Consistent with Executive Order (E.O.) 14096, and the EPA's commitment to upholding environmental justice (EJ) across its policies and programs, the EPA carefully considered the impacts of these actions on communities with environmental justice concerns. As part of the regulatory development process for these rulemakings, and consistent with directives set forth in multiple Executive Orders, the EPA conducted extensive outreach with interested parties including Tribal nations and communities with environmental justice concerns. These opportunities gave the EPA a chance to hear directly from the public, including from communities potentially impacted by these final

[11] *Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability* (March 9, 2023). *https://www.epa.gov/power-sector/electric-reliability-mou.*

actions. The EPA took this feedback into account in its development of these final actions.[12] The EPA's analysis of environmental justice in these final actions is briefly summarized here and discussed in further detail in sections XII.E and XIII.J of the preamble and section 6 of the regulatory impact analysis (RIA).

Several environmental justice organizations and community representatives raised significant concerns about the potential health, environmental, and safety impacts of CCS. The EPA takes these concerns seriously, agrees that any impacts to historically disadvantaged and overburdened communities are important to consider, and has carefully considered these concerns as it finalized its determinations of the BSERs for these rules. The Agency acknowledges that while these final actions will result in large reductions of both GHGs and other emissions that will have significant positive benefits, there is the potential for localized increases in emissions, particularly if units installing CCS operate for more hours during the year and/or for more years than they would have otherwise. However, as discussed in section VII.C.1.a.iii(B), a robust regulatory framework exists to reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. The Council on Environmental Quality's (CEQ) February 2022 *Carbon Capture, Utilization, and Sequestration Guidance* and the EPA's evaluation of BSER recognize that multiple Federal agencies have responsibility for regulating and permitting CCS projects, along with state and tribal governments. As the CEQ has noted, Federal agencies have ''taken actions in the past decade to develop a robust carbon capture, utilization, and sequestration/storage (CCUS) regulatory framework to protect the environment and public health across multiple statutes.'' [13] [14]

Furthermore, the EPA plans to review and update as needed its guidance on NSR permitting, specifically with respect to BACT determinations for GHG emissions and consideration of co-pollutant increases from sources installing CCS. For the reasons explained in section VII.C, the EPA is finalizing the determination that CCS is the BSER for certain subcategories of new and existing EGUs based on its consideration of all of the statutory criteria for BSER, including emission reductions, cost, energy requirements, and non-air health and environmental considerations. At the same time, the EPA recognizes the critical importance of ensuring that the regulatory framework performs as intended to protect communities.

These actions are focused on establishing NSPS and emission guidelines for GHGs that states will implement to significantly reduce GHGs and move us a step closer to avoiding the worst impacts of climate change, which is already having a disproportionate impact on communities with environmental justice concerns. The EPA analyzed several illustrative scenarios representing potential compliance outcomes and evaluated the potential impacts that these actions may have on emissions of GHG and other health-harming air pollutants from fossil fuel-fired EGUs, as well as how these changes in emissions might affect air quality and public health, particularly for communities with EJ concerns.

The EPA's national-level analysis of emission reduction and public health impacts, which is documented in section 6 of the RIA and summarized in greater detail in section XII.A and XII.D of this preamble, finds that these actions achieve nationwide reductions in EGU emissions of multiple health-harming air pollutants including nitrogen oxides (NO_X), sulfur dioxide (SO_2), and fine particulate matter ($PM_{2.5}$), resulting in public health benefits. The EPA also evaluated how the air quality impacts associated with these final actions are distributed, with particular focus on communities with EJ concerns. As discussed in the RIA, our analysis indicates that baseline ozone and $PM_{2.5}$ concentration will decline substantially relative to today's levels. Relative to these low baseline levels, ozone and $PM_{2.5}$ concentrations will decrease further in virtually all areas of the country, although some areas of the country may experience slower or faster rates of decline in ozone and $PM_{2.5}$ pollution over time due to the changes in generation and utilization resulting from these rules. Additionally, our comparison of future air quality conditions with and without these rules suggests that while these actions are anticipated to lead to modest but widespread reductions in ambient levels of $PM_{2.5}$ and ozone for a large majority of the nation's population, there is potential for some geographic areas and demographic groups to experience small increases in ozone concentrations relative to the baseline levels which are projected to be substantially lower than today's levels.

It is important to recognize that while these projections of emissions changes and resulting air quality changes under various illustrative compliance scenarios are based upon the best information available to the EPA at this time, with regard to existing sources, each state will ultimately be responsible for determining the future operation of fossil fuel-fired steam generating units located within its jurisdiction. The EPA expects that, in making these determinations, states will consider a number of factors and weigh input from the wide range of potentially affected stakeholders. The meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders—including community members adversely impacted by pollution, energy workers affected by construction and/or other changes in operation at fossil-fuel-fired power plants, consumers and other interested parties—will have an opportunity to have their concerns heard as states make decisions balancing a multitude of factors including appropriate standards of performance, compliance strategies, and compliance flexibilities for existing EGUs, as well as public health and environmental considerations. The EPA believes that these provisions, together with the protections referenced above, can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

F. Energy Workers and Communities

These final actions include requirements for meaningful engagement in development of state plans, including with energy workers and communities. These communities, including energy workers employed at affected EGUs, workers who may construct and install pollution control technology, workers employed by fuel extraction and delivery, organizations

[12] Specifically, the EPA has relied on, and is incorporating as a basis for this rulemaking, analyses regarding possible adverse environmental effects from CCS, including those highlighted by commenters. Consideration of these effects is permissible under CAA section 111(a)(1). Although the EPA also conducted analyses of disproportionate impacts pursuant to E.O. 14096, see section XII.E, the EPA did not consider or rely on these analyses as a basis for these rules.

[13] 87 FR 8808, 8809 (February 16, 2022).

[14] This framework includes, among other things, the EPA regulation of geologic sequestration wells under the Underground Injection Control (UIC) program of the Safe Drinking Water Act; required reporting and public disclosure of geologic sequestration activity, as well as implementation of rigorous monitoring, reporting, and verification of geologic sequestration under the EPA's Greenhouse Gas Reporting Program (GHGRP); and safety regulations for CO_2 pipelines administered by the Pipeline and Hazardous Materials and Safety Administration (PHMSA).

representing these workers, and communities living near affected EGUs, are impacted by power sector trends on an ongoing basis and by these final actions, and the EPA expects that states will include these stakeholders as part of their constructive engagement under the requirements in this rule.

The EPA consulted with the Federal Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Energy Communities IWG) in development of these rules and the meaningful engagement requirements. The EPA notes that the Energy Communities IWG has provided resources to help energy communities access the expanded federal resources made available by the Bipartisan Infrastructure Law, CHIPS and Science Act, and Inflation Reduction Act, many of which are relevant to the development of state plans.

G. Key Changes From Proposal

The key changes from proposal in these final actions are: (1) the reduction in number of subcategories for existing coal-fired steam generating units, (2) the extension of the compliance date for existing coal-fired steam generating units to meet a standard of performance based on implementation of CCS, (3) the removal of low-GHG hydrogen co-firing as a BSER pathway, and (4) the addition of two reliability-related instruments. In addition, (5), the EPA is not finalizing proposed requirements for existing fossil fuel-fired stationary combustion turbines at this time.

The reduction in number of subcategories for existing coal-fired steam generating units: The EPA proposed four subcategories for existing coal-fired steam generating units, which would have distinguished these units by operating horizon and by load level. These included subcategories for existing coal-fired EGUs planning to cease operations in the imminent-term (*i.e.,* prior to January 1, 2032) and those planning to cease operations in the near-term (*i.e.,* prior to January 1, 2035). While commenters were generally supportive of the proposed subcategorization approach, some requested that the cease-operation-by date for the imminent-term subcategory be extended and the utilization limit for the near-term subcategory be relaxed. The EPA is not finalizing the imminent-term and near-term subcategories of coal-fired steam generating units. Rather, the EPA is finalizing an applicability exemption for coal-fired steam generating units demonstrating that they plan to permanently cease operation before January 1, 2032. See section VII.B of this preamble for further discussion.

The extension of the compliance date for existing coal-fired steam generating units to meet a standard of performance based on implementation of CCS. The EPA proposed a compliance date for implementation of CCS for long-term coal-fired steam generating units of January 1, 2030. The EPA received comments asserting that this deadline did not provide adequate lead time. In consideration of those comments, and the record as a whole, the EPA is finalizing a CCS compliance date of January 1, 2032 for these sources.

The removal of low-GHG hydrogen co-firing as a BSER pathway and only use of low-GHG hydrogen as a compliance option: The EPA is not finalizing its proposed BSER pathway of low-GHG hydrogen co-firing for new and reconstructed base load and intermediate load combustion turbines in accordance with CAA section 111(a)(1). The EPA is also not finalizing its proposed requirement that only low-GHG hydrogen may be co-fired in a combustion turbine for the purpose of compliance with the standards of performance. These decisions are based on uncertainties identified for specific criteria used to evaluate low-GHG hydrogen co-firing as a potential BSER, and after further analysis in response to public comments, the EPA has determined that these uncertainties prevent the EPA from concluding that low-GHG hydrogen co-firing is a component of the ''best'' system of emission reduction at this time. Under CAA section 111, the EPA establishes standards of performance but does not mandate use of any particular technology to meet those standards. Therefore, certain sources may elect to co-fire hydrogen for compliance with the final standards of performance, even absent the technology being a BSER pathway.[15] See section VIII.F.5 of this preamble for further discussion.

The addition of two reliability-related instruments: Commenters expressed concerns that these rules, in combination with other factors, may affect the reliability of the bulk power system. In response to these comments the EPA engaged extensively with balancing authorities, power companies, reliability experts, and regulatory authorities responsible for reliability to inform its decisions in these final rules. As described later in this preamble, the EPA has made adjustments in these final rules that will support power companies, grid operators, and states in maintaining the reliability of the electric grid during the implementation of these final rules. In addition, the EPA has undertaken an analysis of the reliability and resource adequacy implications of these final rules that supports the Agency's conclusion that these final rules can be implemented without adverse consequences for grid reliability. Further, the EPA is finalizing two reliability-related instruments as an additional layer of safeguards for reliability. These instruments include a reliability mechanism for short-term emergency issues, and a reliability assurance mechanism, or compliance flexibility, for units that have chosen compliance pathways with enforceable retirement dates, provided there is a documented and verified reliability concern. In addition, the EPA is finalizing compliance extensions for unanticipated delays with control technology implementation. Specifically, as described in greater detail in section XII.F of this preamble, the EPA is finalizing the following features and changes from the proposal that will provide even greater certainty that these final rules are sensitive to reliability-related issues and constructed in a manner that does not interfere with grid operators' responsibility to deliver reliable power:

(1) longer compliance timelines for existing coal-fired steam generating units;

(2) a mechanism to extend compliance timelines by up to 1 year in the case of unforeseen circumstances, outside of an owner/operator's control, that delay the ability to apply controls (*e.g.,* supply chain challenges or permitting delays);

(3) transparent unit-specific compliance information for EGUs that will allow grid operators to plan for system changes with greater certainty and precision;

(4) a short-term reliability mechanism to allow affected EGUs to operate at

[15] The EPA is not placing qualifications on the type of hydrogen a source may elect to co-fire at this time (see section VIII.F.6.a of this preamble for further discussion). The Agency continues to recognize that even though the combustion of hydrogen is zero-GHG emitting, its production can entail a range of GHG emissions, from low to high, depending on the production method. Thus, even though the EPA is not finalizing the low-GHG hydrogen co-firing as a BSER, as proposed, it maintains that the overall GHG profile of a particular method of hydrogen production should be a primary consideration for any source that decides to co-fire hydrogen to ensure that overall GHG reductions and important climate benefits are achieved. The EPA also notes the anticipated final rule from the U.S. Department of the Treasury pertaining to clean hydrogen production tax and energy credits, which in its proposed form contains certain eligibility parameters, as well as programs administered by the U.S. Department of Energy, such as the recent H2Hubs selections.

baseline emission rates during documented reliability emergencies; and

(5) a reliability assurance mechanism to allow states to delay cease operation dates by up to 1 year in cases where the planned cease operation date is forecast to disrupt system reliability.

Not finalizing proposed requirements for existing fossil fuel-fired stationary combustion turbines at this time: The EPA proposed emission guidelines for large (*i.e.,* greater than 300 MW), frequently operated (*i.e.,* with an annual capacity factor of greater than 50 percent), existing fossil fuel-fired stationary combustion turbines. The EPA received a wide range of comments on the proposed guidelines. Multiple commenters suggested that the proposed provisions would largely result in shifting of generation away from the most efficient natural gas-fired turbines to less efficient natural gas-fired turbines. Commenters stated that, as emissions from coal-fired steam generating units decreased, existing natural gas-fired EGUs were poised to become the largest source of GHG emissions in the power sector. Commenters noted that these units play an important role in grid reliability, particularly as aging coal-fired EGUs retire. Commenters further noted that the existing fossil fuel-fired stationary combustion turbines that were not covered by the proposal (*i.e.,* the smaller and less frequently operating units) are often less efficient, less well controlled for other pollutants such as NO_X, and are more likely to be located near population centers and communities with environmental justice concerns.

The EPA agrees with commenters who observed that GHG emissions from existing natural gas-fired stationary combustion turbines are a growing portion of the emissions from the power sector. This is consistent with EPA modeling that shows that by 2030 these units will represent the largest portion of GHG emissions from the power sector. The EPA agrees that it is vital to promulgate emission guidelines to address GHG emissions from these sources, and that the EPA has a responsibility to do so under section 111(d) of the Clean Air Act. The EPA also agrees with commenters who noted that focusing only on the largest and most frequently operating units, without also addressing emissions from other units, as the May 2023 proposed rule provided, may not be the most effective way to address emissions from this sector. The EPA's modeling shows that over time as the power sector comes closer to reaching the phase-out threshold of the clean electricity incentives in the Inflation Reduction Act (IRA) (*i.e.,* a 75 percent reduction in emissions from the power sector from 2022 levels), the average capacity factor for existing natural gas-fired stationary combustion turbines decreases. Therefore, the EPA's proposal to focus only on the largest units with the highest capacity factors may not be the most effective policy design for reducing GHG emissions from these sources.

Recognizing the importance of reducing emissions from all fossil fuel-fired EGUs, the EPA is not finalizing the proposed emission guidelines for certain existing fossil fuel-fired stationary combustion turbines at this time. Instead, the EPA intends to issue a new, more comprehensive proposal to regulate GHGs from existing sources. The new proposal will focus on achieving greater emission reductions from existing stationary combustion turbines—which will soon be the largest stationary sources of GHG emissions—while taking into account other factors including the local non-GHG impacts of gas turbine generation and the need for reliable, affordable electricity.

II. General Information

A. Action Applicability

The source category that is the subject of these actions is composed of fossil fuel-fired electric utility generating units. The North American Industry Classification System (NAICS) codes for the source category are 221112 and 921150. The list of categories and NAICS codes is not intended to be exhaustive, but rather provides a guide for readers regarding the entities that these final actions are likely to affect.

Final amendments to 40 CFR part 60, subpart TTTT, are directly applicable to affected facilities that began construction after January 8, 2014, but before May 23, 2023, and affected facilities that began reconstruction or modification after June 18, 2014, but before May 23, 2023. The NSPS codified in 40 CFR part 60, subpart TTTTa, is directly applicable to affected facilities that begin construction, reconstruction, or modification on or after May 23, 2023. Federal, state, local, and tribal government entities that own and/or operate EGUs subject to 40 CFR part 60, subpart TTTT or TTTTa, are affected by these amendments and standards.

The emission guidelines codified in 40 CFR part 60, subpart UUUUb, are for states to follow in developing, submitting, and implementing state plans to establish performance standards to reduce emissions of GHGs from designated facilities that are existing sources. Section 111(a)(6) of the CAA defines an ''existing source'' as ''any stationary source other than a new source.'' Therefore, the emission guidelines would not apply to any EGUs that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT. Under the Tribal Authority Rule (TAR), eligible tribes may seek approval to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a tribal implementation plan (TIP) implementing the emission guidelines codified in 40 CFR part 60, subpart UUUUb. The TAR authorizes tribes to develop and implement their own air quality programs, or portions thereof, under the CAA. However, it does not require tribes to develop a CAA program. Tribes may implement programs that are most relevant to their air quality needs. If a tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for designated facilities that are located in areas of Indian country.[16] A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves a TIP applicable to those facilities.

B. Where To Get a Copy of This Document and Other Related Information

In addition to being available in the docket, an electronic copy of these final rulemakings is available on the internet at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power*. Following signature by the EPA Administrator, the EPA will post a copy of these final rulemakings at this same website. Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the final rules and key technical documents at this same website.

C. Judicial Review and Administrative Review

Under CAA section 307(b)(1), judicial review of these final actions is available only by filing a petition for review in

[16] See the EPA's website, *https://www.epa.gov/tribal/tribes-approved-treatment-state-tas*, for information on those tribes that have treatment as a state for specific environmental regulatory programs, administrative functions, and grant programs.

the United States Court of Appeals for the District of Columbia Circuit by July 8, 2024. These final actions are ''standard[s] of performance or requirement[s] under section 111,'' and, in addition, are ''nationally applicable regulations promulgated, or final action taken, by the Administrator under [the CAA],'' CAA section 307(b)(1). Under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment, (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. Environmental Protection Agency, Room 3000, WJC West Building, 1200 Pennsylvania Ave. NW, Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460.

III. Climate Change Impacts

Elevated concentrations of GHGs have been warming the planet, leading to changes in the Earth's climate that are occurring at a pace and in a way that threatens human health, society, and the natural environment. While the EPA is not making any new scientific or factual findings with regard to the well-documented impact of GHG emissions on public health and welfare in support of these rules, the EPA is providing in this section a brief scientific background on climate change to offer additional context for these rulemakings and to help the public understand the environmental impacts of GHGs.

Extensive information on climate change is available in the scientific assessments and the EPA documents that are briefly described in this section, as well as in the technical and scientific information supporting them. One of those documents is the EPA's 2009 ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the CAA'' (74 FR 66496, December 15, 2009) (''2009 Endangerment Finding''). In the 2009 Endangerment Finding, the Administrator found under section 202(a) of the CAA that elevated atmospheric concentrations of six key well-mixed GHGs—CO_2, methane (CH_4), nitrous oxide (N_2O), HFCs, perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—''may reasonably be anticipated to endanger the public health and welfare of current and future generations'' (74 FR 66523, December 15, 2009). The 2009 Endangerment Finding, together with the extensive scientific and technical evidence in the supporting record, documented that climate change caused by human emissions of GHGs threatens the public health of the U.S. population. It explained that by raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses (74 FR 66497, December 15, 2009). While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the U.S. (74 FR 66525, December 15, 2009). The 2009 Endangerment Finding further explained that compared with a future without climate change, climate change is expected to increase tropospheric ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst tropospheric ozone problems, and thereby increase the risk of adverse effects on public health (74 FR 66525, December 15, 2009). Climate change is also expected to cause more intense hurricanes and more frequent and intense storms of other types and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders (74 FR 66525 December 15, 2009). Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects (74 FR 66498, December 15, 2009).

The 2009 Endangerment Finding also documented, together with the extensive scientific and technical evidence in the supporting record, that climate change touches nearly every aspect of public welfare [17] in the U.S., including the following: changes in water supply and quality due to changes in drought and extreme rainfall events; increased risk of storm surge and flooding in coastal areas and land loss due to inundation; increases in peak electricity demand and risks to electricity infrastructure; and the potential for significant agricultural disruptions and crop failures (though offset to some extent by carbon fertilization). These impacts are also global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S. (74 FR 66530, December 15, 2009).

In 2016, the Administrator issued a similar finding for GHG emissions from aircraft under section 231(a)(2)(A) of the CAA.[18] In the 2016 Endangerment Finding, the Administrator found that the body of scientific evidence amassed in the record for the 2009 Endangerment Finding compellingly supported a similar endangerment finding under CAA section 231(a)(2)(A) and also found that the science assessments released between the 2009 and 2016 Findings ''strengthen and further support the judgment that GHGs in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future generations'' (81 FR 54424, August 15, 2016).

Since the 2016 Endangerment Finding, the climate has continued to change, with new observational records being set for several climate indicators such as global average surface temperatures, GHG concentrations, and sea level rise. Additionally, major scientific assessments continue to be released that further advance our understanding of the climate system and the impacts that GHGs have on public health and welfare for both current and future generations. These updated observations and projections document the rapid rate of current and future

[17] The CAA states in section 302(h) that ''[a]ll language referring to effects on welfare includes, but is not limited to, effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other air pollutants.'' 42 U.S.C. 7602(h).

[18] *Finding That Greenhouse Gas Emissions From Aircraft Cause or Contribute to Air Pollution That May Reasonably Be Anticipated To Endanger Public Health and Welfare.* 81 FR 54422, August 15, 2016 (''2016 Endangerment Finding'').

climate change both globally and in the U.S.[19] [20] [21] [22] [23] [24] [25] [26] [27] [28] [29] [30] [31]

The most recent information demonstrates that the climate is continuing to change in response to the human-induced buildup of GHGs in the atmosphere. These recent assessments show that atmospheric concentrations of GHGs have risen to a level that has no precedent in human history and that they continue to climb, primarily because of both historical and current anthropogenic emissions, and that these elevated concentrations endanger our health by affecting our food and water sources, the air we breathe, the weather we experience, and our interactions with the natural and built environments. For example, atmospheric concentrations of one of these GHGs, CO_2, measured at Mauna Loa in Hawaii and at other sites around the world reached 419 parts per million (ppm) in 2022 (nearly 50 percent higher than preindustrial levels) [32] and have continued to rise at a rapid rate. Global average temperature has increased by about 1.1 °C (2.0 °F) in the 2011–2020 decade relative to 1850–1900.[33] The years 2015–2021 were the warmest 7 years in the 1880–2021 record, contributing to the warmest decade on record with a decadal temperature of 0.82 °C (1.48 °F) above the 20th century.[34] [35] The Intergovernmental Panel on Climate Change (IPCC) determined (with medium confidence) that this past decade was warmer than any multi-century period in at least the past 100,000 years.[36] Global average sea level has risen by about 8 inches (about 21 centimeters (cm)) from 1901 to 2018, with the rate from 2006 to 2018 (0.15 inches/year or 3.7 millimeters (mm)/year) almost twice the rate over the 1971 to 2006 period, and three times the rate of the 1901 to 2018 period.[37] The rate of sea level rise over the 20th century was higher than in any other century in at least the last 2,800 years.[38] Higher CO_2 concentrations have led to acidification of the surface ocean in recent decades to an extent unusual in the past 65 million years, with negative impacts on marine organisms that use calcium carbonate to build shells or skeletons.[39] Arctic sea ice extent continues to decline in all months of the year; the most rapid reductions occur in September (very likely almost a 13 percent decrease per decade between 1979 and 2018) and are unprecedented in at least 1,000 years.[40] Human-induced climate change has led to heatwaves and heavy precipitation becoming more frequent and more intense, along with increases in agricultural and ecological droughts [41] in many regions.[42]

The assessment literature demonstrates that modest additional amounts of warming may lead to a climate different from anything humans have ever experienced. The 2022 CO_2 concentration of 419 ppm is already higher than at any time in the last 2 million years.[43] If concentrations exceed 450 ppm, they would likely be higher than any time in the past 23 million years: [44] at the current rate of increase of more than 2 ppm per year, this would occur in about 15 years. While GHGs are not the only factor that controls climate, it is illustrative that 3 million years ago (the last time CO_2 concentrations were above 400 ppm) Greenland was not yet completely covered by ice and still supported forests, while 23 million years ago (the last time concentrations were above 450 ppm) the West Antarctic ice sheet was not yet developed, indicating the possibility that high GHG concentrations could lead to a world that looks very different from today and from the conditions in which human civilization has developed. If the Greenland and Antarctic ice sheets were

[19] USGCRP, 2017: *Climate Science Special Report: Fourth National Climate Assessment,* Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 470 pp, doi: 10.7930/J0J964J6.

[20] USGCRP, 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C.

[21] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi:10.7930/NCA4.2018.

[22] IPCC, 2018: *Global Warming of 1.5 °C.* An IPCC Special Report on the impacts of global warming of 1.5 °C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)].

[23] IPCC, 2019: *Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems* [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Pörtner, D.C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)].

[24] IPCC, 2019: *IPCC Special Report on the Ocean and Cryosphere in a Changing Climate* [H.-O. Pörtner, D.C. Roberts, V. Masson-Delmotte, P. Zhai, M. Tignor, E. Poloczanska, K. Mintenbeck, A. Alegríía, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

[25] National Academies of Sciences, Engineering, and Medicine. 2016. *Attribution of Extreme Weather Events in the Context of Climate Change*. Washington, DC: The National Academies Press. *https://dio.org/10.17226/21852*.

[26] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. Washington, DC: The National Academies Press. *https://doi.org/10.17226/24651*.

[27] National Academies of Sciences, Engineering, and Medicine. 2019. *Climate Change and Ecosystems*. Washington, DC: The National Academies Press. *https://doi.org/10.17226/25504*.

[28] Blunden, J. and T. Boyer, Eds., 2022: ''State of the Climate in 2021.'' Bull. Amer. Meteor. Soc., 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate.1*.

[29] U.S. Environmental Protection Agency. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. EPA 430–R–21–003.

[30] Jay, A.K., A.R. Crimmins, C.W. Avery, T.A. Dahl, R.S. Dodder, B.D. Hamlington, A. Lustig, K. Marvel, P.A. Méndez-Lazaro, M.S. Osler, A. Terando, E.S. Weeks, and A. Zycherman, 2023: Ch. 1. Overview: Understanding risks, impacts, and responses. In: Fifth National Climate Assessment. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. *https://doi.org/10.7930/NCA5.2023.CH1*.

[31] IPCC, 2023: Summary for Policymakers. In: Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)].

[32] *https://gml.noaa.gov/webdata/ccgg/trends/co2/co2_annmean_mlo.txt*.

[33] IPCC, 2021: Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 3–32, doi:10.1017/9781009157896.001.

[34] NOAA National Centers for Environmental Information, State of the Climate 2021 retrieved on August 3, 2023, from *https://www.ncei.noaa.gov/bams-state-of-climate*.

[35] Blunden, J. and T. Boyer, Eds., 2022: ''State of the Climate in 2021.'' Bull. Amer. Meteor. Soc., 103 (8), Si–S465, *https://doi.org/10.1175/2022BAMSStateoftheClimate*1.

[36] IPCC, 2021.

[37] IPCC, 2021.

[38] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi:10.7930/NCA4.2018.

[39] IPCC, 2018.

[40] IPCC, 2021.

[41] These are drought measures based on soil moisture.

[42] IPCC, 2021.

[43] Annual Mauna Loa CO_2 concentration data from *https://gml.noaa.gov/webdata/ccgg/trends/co2/co2_annmean_mlo.txt*, accessed September 9, 2023.

[44] IPCC, 2013.

to melt substantially, sea levels would rise dramatically.

The NCA4 found that it is very likely (greater than 90 percent likelihood) that by mid-century, the Arctic Ocean will be almost entirely free of sea ice by late summer for the first time in about 2 million years.[45] Coral reefs will be at risk for almost complete (99 percent) losses with 1 °C (1.8 °F) of additional warming from today (2 °C or 3.6 °F since preindustrial). At this temperature, between 8 and 18 percent of animal, plant, and insect species could lose over half of the geographic area with suitable climate for their survival, and 7 to 10 percent of rangeland livestock would be projected to be lost.[46] The IPCC similarly found that climate change has caused substantial damages and increasingly irreversible losses in terrestrial, freshwater, and coastal and open ocean marine ecosystems.

Every additional increment of temperature comes with consequences. For example, the half degree of warming from 1.5 to 2 °C (0.9 °F of warming from 2.7 °F to 3.6 °F) above preindustrial temperatures is projected on a global scale to expose 420 million more people to frequent extreme heatwaves at least every five years, and 62 million more people to frequent exceptional heatwaves at least every five years (where heatwaves are defined based on a heat wave magnitude index which takes into account duration and intensity—using this index, the 2003 French heat wave that led to almost 15,000 deaths would be classified as an ''extreme heatwave'' and the 2010 Russian heatwave which led to thousands of deaths and extensive wildfires would be classified as ''exceptional''). It would increase the frequency of sea-ice-free Arctic summers from once in 100 years to once in a decade. It could lead to 4 inches of additional sea level rise by the end of the century, exposing an additional 10 million people to risks of inundation as well as increasing the probability of triggering instabilities in either the Greenland or Antarctic ice sheets. Between half a million and a million additional square miles of permafrost would thaw over several centuries. Risks to food security would increase from medium to high for several lower-income regions in the Sahel, southern Africa, the Mediterranean, central Europe, and the Amazon. In addition to food security issues, this temperature increase would have implications for human health in terms of increasing ozone concentrations, heatwaves, and vector-borne diseases (for example, expanding the range of the mosquitoes which carry dengue fever, chikungunya, yellow fever, and the Zika virus or the ticks which carry Lyme, babesiosis, or Rocky Mountain Spotted Fever).[47] Moreover, every additional increment in warming leads to larger changes in extremes, including the potential for events unprecedented in the observational record. Every additional degree will intensify extreme precipitation events by about 7 percent. The peak winds of the most intense tropical cyclones (hurricanes) are projected to increase with warming. In addition to a higher intensity, the IPCC found that precipitation and frequency of rapid intensification of these storms has already increased, the movement speed has decreased, and elevated sea levels have increased coastal flooding, all of which make these tropical cyclones more damaging.[48]

The NCA4 also evaluated a number of impacts specific to the U.S. Severe drought and outbreaks of insects like the mountain pine beetle have killed hundreds of millions of trees in the western U.S. Wildfires have burned more than 3.7 million acres in 14 of the 17 years between 2000 and 2016, and Federal wildfire suppression costs were about a billion dollars annually.[49] The National Interagency Fire Center has documented U.S. wildfires since 1983, and the 10 years with the largest acreage burned have all occurred since 2004.[50] Wildfire smoke degrades air quality, increasing health risks, and more frequent and severe wildfires due to climate change would further diminish air quality, increase incidences of respiratory illness, impair visibility, and disrupt outdoor activities, sometimes thousands of miles from the location of the fire. Meanwhile, sea level rise has amplified coastal flooding and erosion impacts, requiring the installation of costly pump stations, flooding streets, and increasing storm surge damages. Tens of billions of dollars of U.S. real estate could be below sea level by 2050 under some scenarios. Increased frequency and duration of drought will reduce agricultural productivity in some regions, accelerate depletion of water supplies for irrigation, and expand the distribution and incidence of pests and diseases for crops and livestock. The NCA4 also recognized that climate change can increase risks to national security, both through direct impacts on military infrastructure and by affecting factors such as food and water availability that can exacerbate conflict outside U.S. borders. Droughts, floods, storm surges, wildfires, and other extreme events stress nations and people through loss of life, displacement of populations, and impacts on livelihoods.[51] The NCA5 further reinforces the science showing that climate change will have many impacts on the U.S., as described above in the preamble. Particularly relevant for these rules, the NCA5 states that climate change affects all aspects of the energy system-supply, delivery, and demand-through the increased frequency, intensity, and duration of extreme events and through changing climate trends.'' [52]

EPA modeling efforts can further illustrate how these impacts from climate change may be experienced across the U.S. EPA's Framework for Evaluating Damages and Impacts (FrEDI) [53] uses information from over 30 peer-reviewed climate change impact studies to project the physical and economic impacts of climate change to the U.S. resulting from future temperature changes. These impacts are projected for specific regions within the U.S. and for more than 20 impact categories, which span a large number of sectors of the U.S. economy.[54] Using

[45] USGCRP, 2018.

[46] IPCC, 2018.

[47] IPCC, 2018.

[48] IPCC, 2021.

[49] USGCRP, 2018.

[50] NIFC (National Interagency Fire Center). 2021. Total wildland fires and acres (1983–2020). Accessed August 2021. *https://www.nifc.gov/fireInfo/fireInfo_stats_totalFires.html.*

[51] USGCRP, 2018.

[52] Jay, A.K., A.R. Crimmins, C.W. Avery, T.A. Dahl, R.S. Dodder, B.D. Hamlington, A. Lustig, K. Marvel, P.A. Méndez-Lazaro, M.S. Osler, A. Terando, E.S. Weeks, and A. Zycherman, 2023: Ch. 1. Overview: Understanding risks, impacts, and responses. In: *Fifth National Climate Assessment.* Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. *https://doi.org/10.7930/NCA5.2023.CH1.*

[53] (1) Hartin, C., *et al.* (2023). Advancing the estimation of future climate impacts within the United States. Earth Syst. Dynam., 14, 1015–1037, *https://doi.org/10.5194/esd-14-1015-2023.* (2) Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,'' Docket ID No. EPA–HQ–OAR–2021–0317, November 2023, (3) *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050.* Published by the U.S. Department of State and the U.S. Executive Office of the President, Washington DC. November 2021, (4) *Climate Risk Exposure: An Assessment of the Federal Government's Financial Risks to Climate Change,* White Paper, Office of Management and Budget, April 2022.

[54] EPA (2021). Technical Documentation on the Framework for Evaluating Damages and Impacts (FrEDI). U.S. Environmental Protection Agency, EPA 430–R–21–004, *https://www.epa.gov/cira/fredi.* Documentation has been subject to both a public review comment period and an independent

Continued

this framework, the EPA estimates that global emission projections, with no additional mitigation, will result in significant climate-related damages to the U.S.[55] These damages to the U.S. would mainly be from increases in lives lost due to increases in temperatures, as well as impacts to human health from increases in climate-driven changes in air quality, dust and wildfire smoke exposure, and incidence of suicide. Additional major climate-related damages would occur to U.S. infrastructure such as roads and rail, as well as transportation impacts and coastal flooding from sea level rise, increases in property damage from tropical cyclones, and reductions in labor hours worked in outdoor settings and buildings without air conditioning. These impacts are also projected to vary from region to region with the Southeast, for example, projected to see some of the largest damages from sea level rise, the West Coast projected to experience damages from wildfire smoke more than other parts of the country, and the Northern Plains states projected to see a higher proportion of damages to rail and road infrastructure. While information on the distribution of climate impacts helps to better understand the ways in which climate change may impact the U.S., recent analyses are still only a partial assessment of climate impacts relevant to U.S. interests and in addition do not reflect increased damages that occur due to interactions between different sectors impacted by climate change or all the ways in which physical impacts of climate change occurring abroad have spillover effects in different regions of the U.S.

Some GHGs also have impacts beyond those mediated through climate change. For example, elevated concentrations of CO_2 stimulate plant growth (which can be positive in the case of beneficial species, but negative in terms of weeds and invasive species, and can also lead to a reduction in plant micronutrients [56]) and cause ocean acidification. Nitrous oxide depletes the levels of protective stratospheric ozone.[57] Methane reacts to form tropospheric ozone.

Section XII.E of this preamble discusses the impacts of GHG emissions on individuals living in socially and economically vulnerable communities. While the EPA did not conduct modeling to specifically quantify changes in climate impacts resulting from these rules in terms of avoided temperature change or sea-level rise, the Agency did quantify climate benefits by monetizing the emission reductions through the application of the social cost of greenhouse gases (SC–GHGs), as described in section XII.D of this preamble.

These scientific assessments, the EPA analyses, and documented observed changes in the climate of the planet and of the U.S. present clear support regarding the current and future dangers of climate change and the importance of GHG emissions mitigation.

IV. Recent Developments in Emissions Controls and the Electric Power Sector

In this section, we discuss background information about the electric power sector and controls available to limit GHG pollution from the fossil fuel-fired power plants regulated by these final rules, and then discuss several recent developments that are relevant for determining the BSER for these sources. After giving some general background, we first discuss CCS and explain that its costs have fallen significantly. Lower costs are central for the EPA's determination that CCS is the BSER for certain existing coal-fired steam generating units and certain new natural gas-fired combustion turbines. Second, we discuss natural gas co-firing for coal-fired steam generating units and explain recent reductions in cost for this approach as well as its widespread availability and current and potential deployment within this subcategory. Third, we discuss highly efficient generation as a BSER technology for new and reconstructed simple cycle and combined cycle combustion turbine EGUs. The emission reductions achieved by highly efficient turbines are well demonstrated in the power sector, and along with operational and maintenance best practices, represent a cost-effective technology that reduces fuel consumption. Finally, we discuss key developments in the electric power sector that influence which units can feasibly and cost-effectively deploy these technologies.

A. Background

1. Electric Power Sector

Electricity in the U.S. is generated by a range of technologies, and different EGUs play different roles in providing reliable and affordable electricity. For example, certain EGUs generate base load power, which is the portion of electricity loads that are continually present and typically operate throughout all hours of the year. Intermediate EGUs often provide complementary generation to balance variable supply and demand resources. Low load ''peaking units'' provide capacity during hours of the highest daily, weekly, or seasonal net demand, and while these resources have low levels of utilization on an annual basis, they play important roles in providing generation to meet short-term demand and often must be available to quickly increase or decrease their output. Furthermore, many of these EGUs also play important roles ensuring the reliability of the electric grid, including facilitating the regulation of frequency and voltage, providing ''black start'' capability in the event the grid must be repowered after a widespread outage, and providing reserve generating capacity [58] in the event of unexpected changes in the availability of other generators.

In general, the EGUs with the lowest operating costs are dispatched first, and, as a result, an inefficient EGU with high fuel costs will typically only operate if other lower-cost plants are unavailable or are insufficient to meet demand. Units are also unavailable during both routine and unanticipated outages, which typically become more frequent as power plants age. These factors result in the mix of available generating capacity types (*e.g.,* the share of capacity of each type of generating source) being substantially different than the mix of the share of total electricity produced by each type of generating source in a given season or year.

expert peer review, following EPA peer-review guidelines.

[55] Compared to a world with no additional warming after the model baseline (1986–2005).

[56] Ziska, L., A. Crimmins, A. Auclair, S. DeGrasse, J.F. Garofalo, A.S. Khan, I. Loladze, A.A. Pérez de León, A. Showler, J. Thurston, and I. Walls, 2016: Ch. 7: *Food Safety, Nutrition, and Distribution. The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* U.S. Global Change Research Program, Washington, DC, 189–216. *https://health2016.globalchange.gov/low/ClimateHealth2016_07_Food_small.pdf.*

[57] WMO (World Meteorological Organization), *Scientific Assessment of Ozone Depletion: 2018, Global Ozone Research and Monitoring Project*—Report No. 58, 588 pp., Geneva, Switzerland, 2018.

[58] Generation and capacity are commonly reported statistics with key distinctions. Generation is the production of electricity and is a measure of an EGU's *actual* output while capacity is a measure of the maximum *potential* production of an EGU under certain conditions. There are several methods to calculate an EGU's capacity, which are suited for different applications of the statistic. Capacity is typically measured in megawatts (MW) for individual units or gigawatts (1 GW = 1,000 MW) for multiple EGUs. Generation is often measured in kilowatt-hours (1 kWh = 1,000 watt-hours), megawatt-hours (1 MWh = 1,000 kWh), gigawatt-hours (1 GWh = 1 million kWh), or terawatt-hours (1 TWh = 1 billion kWh).

Generated electricity must be transmitted over networks [59] of high voltage lines to substations where power is stepped down to a lower voltage for local distribution. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in balance. In some areas, the operation of the transmission system is under the control of a single regional operator; [60] in others, individual utilities [61] coordinate the operations of their generation and transmission to balance the system across their respective service territories.

2. Types of EGUs

There are many types of EGUs including fossil fuel-fired power plants (*i.e.,* those using coal, oil, and natural gas), nuclear power plants, renewable generating sources (such as wind and solar) and others. This rule focuses on the fossil fuel-fired portion of the generating fleet that is responsible for the vast majority of GHG emissions from the power sector. The definition of fossil fuel-fired electric utility steam generating units includes utility boilers as well as those that use gasification technology (*i.e.,* integrated gasification combined cycle (IGCC) units). While coal is the most common fuel for fossil fuel-fired utility boilers, natural gas can also be used as a fuel in these EGUs and many existing coal- and oil-fired utility boilers have refueled as natural gas-fired utility boilers. An IGCC unit gasifies fuel—typically coal or petroleum coke—to form a synthetic gas (or syngas) composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power. The heat created by these technologies produces high-pressure steam that is released to rotate turbines, which, in turn, spin an electric generator.

Stationary combustion turbine EGUs (most commonly natural gas-fired) use one of two configurations: combined cycle or simple cycle turbines. Combined cycle units have two generating components (*i.e.,* two cycles) operating from a single source of heat. Combined cycle units first generate power from a combustion turbine (*i.e.,* the combustion cycle) directly from the heat of burning natural gas or other fuel. The second cycle reuses the waste heat from the combustion turbine engine, which is routed to a heat recovery steam generator (HRSG) that generates steam, which is then used to produce additional power using a steam turbine (*i.e.,* the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Combined cycle units that fire mostly natural gas are commonly referred to as natural gas combined cycle (NGCC) units, and, with greater efficiency, are utilized at higher capacity factors to provide base load or intermediate load power. An EGU's capacity factor indicates a power plant's electricity output as a percentage of its total generation capacity. Simple cycle turbines only use a combustion turbine to produce electricity (*i.e.,* there is no heat recovery or steam cycle). These less-efficient combustion turbines are generally utilized at non-base load capacity factors and contribute to reliable operations of the grid during periods of peak demand or provide flexibility to support increased generation from variable energy sources.[62]

Other generating sources produce electricity by harnessing kinetic energy from flowing water, wind, or tides, thermal energy from geothermal wells, or solar energy primarily through photovoltaic solar arrays. Spurred by a combination of declining costs, consumer preferences, and government policies, the capacity of these renewable technologies is growing, and when considered with existing nuclear energy, accounted for 40 percent of the overall net electricity supply in 2022. Many projections show this share growing over time. For example, the EPA's Power Sector Platform 2023 using IPM (*i.e.,* the EPA's baseline projections of the power sector) projects zero-emitting sources reaching 76 percent of electricity generation by 2040. This shift is driven by multiple factors. These factors include changes in the relative economics of generating technologies, the efforts by states to reduce GHG emissions, utility and other corporate commitments, and customer preference. The shift is further promoted by provisions of Federal legislation, most notably the Clean Electricity Investment and Production tax credits included in IRC sections 48E and 45Y of the IRA, which do not begin to phase out until the later of 2032 or when power sector GHG emissions are 75 percent less than 2022 levels. (See section IV.F of this preamble and the accompanying RIA for additional discussion of projections for the power sector.) These projections are consistent with power company announcements. For example, as the Edison Electric Institute (EEI) stated in pre-proposal public comments submitted to the regulatory docket: ''Fifty EEI members have announced forward-looking carbon reduction goals, two-thirds of which include a net-zero by 2050 or earlier equivalent goal, and members are routinely increasing the ambition or speed of their goals or altogether transforming them into net-zero goals . . . . EEI's member companies see a clear path to continued emissions reductions over the next decade using current technologies, including nuclear power, natural gas-based generation, energy demand efficiency, energy storage, and deployment of new renewable energy—especially wind and solar—as older coal-based and less-efficient natural gas-based generating units retire.'' [63] The Energy Strategy Coalition similarly said in public comments that ''[a]s major electrical utilities and power producers, our top priority is providing clean, affordable, and reliable energy to our customers'' and are ''seeking to advance'' technologies ''such as a carbon capture and storage, which can significantly reduce carbon dioxide

[59] The three network interconnections are the Western Interconnection, comprising the western parts of the U.S. and Canada, the Eastern Interconnection, comprising the eastern parts of the U.S. and Canada except parts of Eastern Canada in the Quebec Interconnection, and the Texas Interconnection, encompassing the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT). See map of all NERC interconnections at *https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC%20Interconnections.pdf.*

[60] For example, PJM Interconnection, LLC, New York Independent System Operator (NYISO), Midwest Independent System Operator (MISO), California Independent System Operator (CAISO), *etc.*

[61] For example, Los Angeles Department of Power and Water, Florida Power and Light, *etc.*

[62] Non-dispatchable renewable energy (electrical output cannot be used at any given time to meet fluctuating demand) is both variable and intermittent and is often referred to as intermittent renewable energy. The variability aspect results from predictable changes in electric generation (*e.g.,* solar not generating electricity at night) that often occur on longer time periods. The intermittent aspect of renewable energy results from inconsistent generation due to unpredictable external factors outside the control of the owner/operator (*e.g.,* imperfect local weather forecasts) that often occur on shorter time periods. Since renewable energy fluctuates over multiple time periods, grid operators are required to adjust forecast and real time operating procedures. As more renewable energy is added to the electric grid and generation forecasts improve, the intermittency of renewable energy is reduced.

[63] Edison Electric Institute (EEI). (November 18, 2022). *Clean Air Act Section 111 Standards and the Power Sector: Considerations and Options for Setting Standards and Providing Compliance Flexibility to Units and States.* Public comments submitted to the EPA's pre-proposal rulemaking, Document ID No. EPA–HQ–OAR–2022–0723–0024.

emissions from fossil fuel-fired EGUs.'' [64]

B. GHG Emissions From Fossil Fuel-Fired EGUs

The principal GHGs that accumulate in the Earth's atmosphere above pre-industrial levels because of human activity are CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. Of these, CO_2 is the most abundant, accounting for 80 percent of all GHGs present in the atmosphere. This abundance of CO_2 is largely due to the combustion of fossil fuels by the transportation, electricity, and industrial sectors.[65]

The amount of CO_2 produced when a fossil fuel is burned in an EGU is a function of the carbon content of the fuel relative to the size and efficiency of the EGU. Different fuels emit different amounts of CO_2 in relation to the energy they produce when combusted. The heat content, or the amount of energy produced when a fuel is burned, is mainly determined by the carbon and hydrogen content of the fuel. For example, in terms of pounds of CO_2 emitted per million British thermal units of energy produced when combusted, natural gas is the lowest compared to other fossil fuels at 117 lb CO_2/MMBtu.[66] [67] The average for coal is 216 lb CO_2/MMBtu, but varies between 206 to 229 lb CO_2/MMBtu by type (*e.g.,* anthracite, lignite, subbituminous, and bituminous).[68] The value for petroleum products such as diesel fuel and heating oil is 161 lb CO_2/MMBtu.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks [69] (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It presents total U.S. anthropogenic emissions and sinks [70] of GHGs, including CO_2 emissions since 1990. According to the latest inventory of all sectors, in 2021, total U.S. GHG emissions were 6,340 million metric tons of CO_2 equivalent (MMT CO_2e).[71] The transportation sector (28.5 percent), which includes approximately 300 million vehicles, was the largest contributor to total U.S. GHG emissions with 1,804 MMT CO_2e followed by the power sector (25.0 percent) with 1,584 MMT CO_2e. In fact, GHG emissions from the power sector were higher than the GHG emissions from all other industrial sectors combined (1,487 MMT CO_2e). Specifically, the power sector's emissions were far more than petroleum and natural gas systems [72] at 301 MMT CO_2e; chemicals (71 MMT CO_2e); minerals (64 MMT CO_2e); coal mining (53 MMT CO_2e); and metals (48 MMT CO_2e). The agriculture (636 MMT CO_2e), commercial (439 MMT CO_2e), and residential (366 MMT CO_2e) sectors combined to emit 1,441 MMT CO_2e.

Fossil fuel-fired EGUs are by far the largest stationary source emitters of GHGs in the nation. For example, according to the EPA's Greenhouse Gas Reporting Program (GHGRP), of the top 100 large facilities that reported facility-level GHGs in 2022, 85 were fossil fuel-fired power plants while 10 were refineries and/or chemical plants, four were metals facilities, and one was a petroleum and natural gas systems facility.[73] Of the 85 fossil fuel-fired power plants, 81 were primarily coal-fired, including the top 41 emitters of CO_2. In addition, of the 81 coal-fired plants, 43 have no retirement planned prior to 2039. The top 10 of these plants combined to emit more than 135 MMT of CO_2e, with the top emitter (James H. Miller power plant in Alabama) reporting approximately 22 MMT of CO_2e with each of its four EGUs emitting between 5 MMT and 6 MMT CO_2e that year. The combined capacity of these 10 plants is more than 23 gigawatts (GW), and all except for the Monroe (Michigan) plant operated at annual capacity factors of 50 percent or higher.[74] For comparison, the largest GHG emitter in the U.S. that is not a fossil fuel-fired power plant is the ExxonMobil refinery and chemical plant in Baytown, Texas, which reported 12.6 MMT CO_2e (No. 6 overall in the nation) to the GHGRP in 2022. The largest metals facility in terms of GHG emissions was the U.S. Steel facility in Gary, Indiana, with 10.4 MMT CO_2e (No. 16 overall in the nation).

Overall, CO_2 emissions from the power sector have declined by 36 percent since 2005 (when the power sector reached annual emissions of 2,400 MMT CO_2, its historical peak to date).[75] The reduction in CO_2 emissions can be attributed to the power sector's ongoing trend away from carbon-intensive coal-fired generation and toward more natural gas-fired and renewable sources. In 2005, CO_2 emissions from coal-fired EGUs alone measured 1,983 MMT.[76] This total dropped to 1,351 MMT in 2015 and reached 974 MMT in 2019, the first time since 1978 that CO_2 emissions from coal-fired EGUs were below 1,000 MMT. In 2020, emissions of CO_2 from coal-fired EGUs measured 788 MMT as the result of pandemic-related closures and reduced utilization before rebounding in 2021 to 909 MMT. By contrast, CO_2 emissions from natural gas-fired generation have almost doubled since 2005, increasing from 319 MMT to 613 MMT in 2021, and CO_2 emissions from petroleum products (*i.e.,* distillate fuel oil, petroleum coke, and residual fuel oil) declined from 98 MMT in 2005 to 18 MMT in 2021.

[64] Energy Strategy Coalition Comments on EPA's proposed New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, Document ID No. EPA–HQ–OAR–2023–0072–0672, August 14, 2023.

[65] U.S. Environmental Protection Agency (EPA). Overview of greenhouse gas emissions. July 2021. *https://www.epa.gov/ghgemissions/overview-greenhouse-gases#carbon-dioxide.*

[66] Natural gas is primarily CH_4, which has a higher hydrogen to carbon atomic ratio, relative to other fuels, and thus, produces the least CO_2 per unit of heat released. In addition to a lower CO_2 emission rate on a lb/MMBtu basis, natural gas is generally converted to electricity more efficiently than coal. According to EIA, the 2020 emissions rate for coal and natural gas were 2.23 lb CO_2/kWh and 0.91 lb CO_2/kWh, respectively. *www.eia.gov/tools/faqs/faq.php?id=74&t=11.*

[67] Values reflect the carbon content on a per unit of energy produced on a higher heating value (HHV) combustion basis and are not reflective of recovered useful energy from any particular technology.

[68] Energy Information Administration (EIA). *Carbon Dioxide Emissions Coefficients. https://www.eia.gov/environment/emissions/co2_vol_mass.php.*

[69] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021.*

[70] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep-sea reservoirs of carbon dioxide.

[71] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.*

[72] Petroleum and natural gas systems include: offshore and onshore petroleum and natural gas production; onshore petroleum and natural gas gathering and boosting; natural gas processing; natural gas transmission/compression; onshore natural gas transmission pipelines; natural gas local distribution companies; underground natural gas storage; liquified natural gas storage; liquified natural gas import/export equipment; and other petroleum and natural gas systems.

[73] U.S. Environmental Protection Agency (EPA). Greenhouse Gas Reporting Program. Facility Level Information on Greenhouse Gases Tool (FLIGHT). *https://ghgdata.epa.gov/ghgp/main.do#.*

[74] U.S. Energy Information Administration (EIA). Preliminary Monthly Electric Generator Inventory, Form EIA–860M, November 2023. *https://www.eia.gov/electricity/data/eia860m/.*

[75] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020. https://cfpub.epa.gov/ghgdata/inventoryexplorer/#electricitygeneration/entiresector/allgas/category/all.*

[76] U.S. Energy Information Administration (EIA). Monthly Energy Review, table 11.6. September 2022. *https://www.eia.gov/totalenergy/data/monthly/pdf/sec11.pdf.*

When the EPA finalized the Clean Power Plan (CPP) in October 2015, the Agency projected that, as a result of the CPP, the power sector would reduce its annual CO_2 emissions to 1,632 MMT by 2030, or 32 percent below 2005 levels (2,400 MMT).[77] Instead, even in the absence of Federal regulations for existing EGUs, annual CO_2 emissions from sources covered by the CPP had fallen to 1,540 MMT by the end of 2021, a nearly 36 percent reduction below 2005 levels. The power sector achieved a deeper level of reductions than forecast under the CPP and approximately a decade ahead of time. By the end of 2015, several months after the CPP was finalized, those sources already had achieved CO_2 emission levels of 1,900 MMT, or approximately 21 percent below 2005 levels. However, progress in emission reductions is not uniform across all states and is not guaranteed to continue, therefore Federal policies play an essential role. As discussed earlier in this section, the power sector remains a leading emitter of CO_2 in the U.S., and, despite the emission reductions since 2005, current CO_2 levels continue to endanger human health and welfare. Further, as sources in other sectors of the economy turn to electrification to decarbonize, future CO_2 reductions from fossil fuel-fired EGUs have the potential to take on added significance and increased benefits.

C. Recent Developments in Emissions Control

This section of the preamble describes recent developments in GHG emissions control in general. Details of those controls in the context of BSER determination are provided in section VII.C.1.a for CCS on coal-fired steam generating units, section VII.C.2.a for natural gas co-firing on coal-fired steam generating units, section VIII.F.2.b for efficient generation on natural gas-fired combustion turbines, and section VIII.F.4.c.iv for CCS on natural gas-fired combustion turbines. Further details of the control technologies are available in the final TSDs, *GHG Mitigation Measures for Steam Generating Units* and *GHG Mitigation Measures—CCS for Combustion Turbines,* available in the docket for these actions.

1. CCS

One of the key GHG reduction technologies upon which the BSER determinations are founded in these final rules is CCS—a technology that can capture and permanently store CO_2 from fossil fuel-fired EGUs. CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s[78] and has been used in a variety of industrial applications for decades. Thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[79] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with enhanced oil recovery (EOR).[80] The American Petroleum Institute (API) explains that ''CCS is a proven technology'' and that ''[t]he methods that apply to [the] carbon sequestration process are not novel. The U.S. has more than 40 years of CO_2 gas injection and storage experience. During the last 40 years the U.S. gas and oil industry's (EOR) enhanced oil recovery operations) have injected more than 1 billion tonnes of CO_2.'' [81] [82]

In 2009, Mike Morris, then-CEO of American Electric Power (AEP), was interviewed by Reuters and the article noted that Morris's ''companies' work in West Virginia on [CCS] gave [Morris] more insight than skeptics who doubt the technology.'' In that interview, Morris explained, ''I'm convinced it will be primetime ready by 2015 and deployable.'' [83] In 2011, Alstom Power, the company that developed the 30 MW pilot project upon which Morris had based his conclusions, reiterated the claim that CCS would be commercially available in 2015. A press release from Alstom Power stated that, based on the results of Alstom's ''13 pilot and demonstration projects and validated by independent experts . . . we can now be confident that CCS works and is cost effective . . . and will be available at a commercial scale in 2015 and will allow [plants] to capture 90% of the emitted CO_2.'' The press release went on to note that ''the same conclusion applies for a gas plant using CCS.'' [84]

In 2011, however, AEP determined that the economic and regulatory environment at the time did not support further development of the technology. After canceling a large-scale commercial project, Morris explained, ''as a regulated utility, it is impossible to gain regulatory approval to cover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place.'' [85]

Thirteen years later, the situation is fundamentally different. Since 2011, the technological advances from full-scale deployments (*e.g.,* the Petra Nova and Boundary Dam projects discussed later in this preamble) combined with supportive policies in multiple states and the financial incentives included in the IRA, mean that CCS can be deployed at scale today. In addition to applications at fossil fuel-fired EGUs, installation of CCS is poised to dramatically increase across a range of industries in the coming years, including ethanol production, natural gas processing, and steam methane reformers.[86] Many of the CCS projects across these industries, including capture systems, pipelines, and sequestration, are already in operation or are in advanced stages of deployment. There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under

[77] 80 FR 63662 (October 23, 2015).

[78] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[79] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[80] GHGRP US EPA. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[81] American Petroleum Institute (API). (2024). Carbon Capture and Storage: A Low-Carbon Solution to Economy-Wide Greenhouse Gas Emissions Reductions. *https://www.api.org/news-policy-and-issues/carbon-capture-storage.*

[82] Major energy company presidents have made similar statements. For example, in 2021, Shell Oil Company president Gretchen H. Watkins testified to Congress that ''Carbon capture and storage is a proven technology,'' and in 2022, Joe Blommaert, the president of ExxonMobil Low Carbon Solutions, stated that ''Carbon capture and storage is a readily available technology that can play a critical role in helping society reduce greenhouse gas emissions.'' See *https://www.congress.gov/117/meeting/house/114185/witnesses/HHRG-117-GO00-Wstate-WatkinsG-20211028.pdf* and *https://corporate.exxonmobil.com/news/news-releases/2022/0225_exxonmobil-to-expand-carbon-capture-and-storage-at-labarge-wyoming-facility.*

[83] Woodall, B. (June 25, 2009). AEP sees carbon capture from coal ready by 2015. Reuters. *https://www.reuters.com/article/idUSTRE55O6TS/.*

[84] Alstom Power. (June 14, 2011). Alstom Power study demonstrates carbon capture and storage (CCS) is efficient and cost competitive. *https://www.alstom.com/press-releases-news/2011/6/press-releases-3-26.*

[85] Indiana Michigan Power. (July 14, 2011). AEP Places Carbon Capture Commercialization on Hold, Citing Uncertain Status of Climate Policy, Weak Economy. Press release. *https://www.indianamichiganpower.com/company/news/view?releaseID=1206.*

[86] U.S. Department of Energy (DOE). (2023). Pathways to Commercial Liftoff: Carbon Management. *https://liftoff.energy.gov/wp-content/uploads/2024/02/20230424-Liftoff-Carbon-Management-vPUB_update4.pdf.*

construction or in advanced stages of development.[87]

Process improvements learned from earlier deployments of CCS, the availability of better solvents, and other advances have decreased the costs of CCS in recent years. As a result, the cost of CO_2 capture, excluding any tax credits, from coal-fired power generation is projected to fall by 50 percent by 2025 compared to 2010.[88] The IRA makes additional and significant reductions in the cost of implementing CCS by extending and increasing the tax credit for CO_2 sequestration under IRC section 45Q.

With this combination of polices, and the advances related to CO_2 capture, multiple projects consistent with the emission reduction requirements of a 90 percent capture amine based BSER are in advanced stages of development. These projects use a wider range of technologies, and some of them are being developed as first-of-a-kind projects and offer significant advantages over the amine-based CCS technology that the EPA is finalizing as BSER.

For instance, in North Dakota, Governor Doug Burgum announced a goal of becoming carbon neutral by 2030 while retaining the core position of its fossil fuel industries, and to do so by significant CCS implementation. Gov. Burgum explained, ''This may seem like a moonshot goal, but it's actually not. It's actually completely doable, even with the technologies that we have today.'' [89] Companies in the state are backing up this claim with projects in multiple industries in various stages of operation and development. In the power sector, two of the biggest projects under development are Project Tundra and Coal Creek. Project Tundra is a carbon capture project on Minnkota Power's 705 MW Milton R Young Power Plant in Oliver County, North Dakota. Mitsubishi Heavy Industries will be providing an advanced version of its carbon capture equipment that builds upon the lessons learned from the Petra Nova project.[90] Rainbow Energy is developing the project at the Coal Creek Station, located in McLean, North Dakota. Notably, Rainbow Energy purchased the 1,150 MW Coal Creek Station with a business model of installing CCS based on the IRC section 45Q tax credit of $50/ton that existed at the time (the IRA has since increased the amount to $85/ton).[91] Rainbow Energy explains, ''CCUS technology has been proven and is an economical option for a facility like Coal Creek Station. We see CCUS as the best way to manage emissions at our facility.'' [92]

While North Dakota has encouraged CCS on coal-fired power plants without specific mandates, Wyoming is taking a different approach. Senate Bill 42, enacted in 2024, requires utilities to generate a specified percentage of their electricity using coal-fired power plants with CCS. SB 42 updates HB 200, enacted in 2020, which required the CCS to be installed by 2030, which SB 42 extends to 2033. To comply with those requirements, PacificCorp has stated in its 2023 IRP that it intends to install CCS on two coal-fired units by 2028.[93] Rocky Mountain Power has also announced that it will explore a new carbon capture technology at either its David Johnston plant or its Wyodak plant.[94] Another CCS project is also under development at the Dry Fork Power Plant in Wyoming. Currently, a pilot project that will capture 150 tons of CO_2 per day is under construction and is scheduled to be completed in late 2024. Work has also begun on a full-scale front end engineering design (FEED) study.

Like North Dakota, West Virginia does not have a carbon capture mandate, but there are several carbon capture projects under development in the state. One is a new, 2,000 MW natural gas combined cycle plant being developed by Competitive Power Ventures that will capture 90–95 percent of the CO_2 using GE turbine and carbon capture technology.[95] A second is an Omnis Fuel Technologies project to convert the coal-fired Pleasants Power Station to run on hydrogen.[96] Omnis intends to use a pyrolysis-based process to convert coal into hydrogen and graphite. Because the graphite is a usable, solid form of carbon, no CO_2 sequestration will be required. Therefore, unlike more traditional amine-based approaches, instead of the captured CO_2 being a cost, the graphite product will provide a revenue stream.[97] Omnis states that the Pleasants Power Project broke ground in August 2023 and will be online by 2025.

It should be noted that Wyoming, West Virginia, and North Dakota represented the first-, second-, and seventh-largest coal producers, respectively, in the U.S. in 2022.[98]

In addition to the coal-based CCS projects mentioned above, multiple other projects are in advanced stages of development and/or have completed FEED studies. For instance, Linde/BASF is installing a 10 MW pilot project on the Dallman Power Plant in Illinois. Based on results from small scale pilot studies, techno economic analysis indicates that the Linde/BASF process can provide a significant reduction in capital costs compared to the NETL base case for a supercritical pulverized coal plant with carbon capture.'' [99] Multiple other FEED studies are either completed or under development, putting those projects on a path to being able to be built and to commence operation well before January 1, 2032.

In addition to the Competitive Power Partners project, there are multiple post-combustion CCS retrofit projects in various stages of development. In particular, NET Power is in advanced stages of development on a 300 MW project in west Texas using the Allam-Fetvedt cycle, which is being designed to achieve greater than 97 percent CO_2 capture. In addition to working on this first project, NET Power has indicated that it has an additional project under development and is working with

[87] Congressional Budget Office (CBO). (December 13, 2023). Carbon Capture and Storage in the United States. *https://www.cbo.gov/publication/59345*.

[88] Global CCS Institute. (March 2021). Technology Readiness and Costs of CCS. *https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf*.

[89] Willis, A. (May 12, 2021). Gov. Doug Burgum calls for North Dakota to be carbon neutral by 2030. The Dickinson Press. *https://www.thedickinsonpress.com/business/gov-doug-burgum-calls-for-north-dakota-to-be-carbon-neutral-by-2030*.

[90] Tanaka, H. et al. Advanced KM CDR Process using New Solvent. 14th International Conference on Greenhouse Gas Control Technologies, GHGT–14. *https://www.cfaenm.org/wp-content/uploads/2019/03/GHGT14_manuscript_20180913Clean-version.pdf*.

[91] Minot Daily News. (April 8, 2024). Hoeven: ND to lead country with carbon capture project at Coal Creek Station. *https://minotdailynews.com/news/local-news/2021/07/hoeven-nd-to-lead-country-with-carbon-capture-project-at-coal-creek-station/*.

[92] Rainbow Energy Center. (ND). Carbon Capture. *https://rainbowenergycenter.com/what-we-do/carbon-capture/*.

[93] PacifiCorp. (April 1, 2024). 2023 Integrated Resource Plan Update. *https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023_IRP_Update.pdf*.

[94] Rocky Mountain Power. (April 1, 2024). Rocky Mountain Power and 8 Rivers to collaborate on proposed Wyoming carbon capture project. Press release. *https://www.rockymountainpower.net/about/newsroom/news-releases/rmp-proposed-wyoming-carbon-capture-project.html*.

[95] Competitive Power Ventures (CPV). Shay Clean Energy Center. *https://www.cpv.com/our-projects/cpv-shay-energy-center/*.

[96] The Associated Press (AP). (August 30, 2023). New owner restarts West Virginia coal-fired power plant and intends to convert it to hydrogen use. *https://apnews.com/article/west-virginia-power-plant-coal-hydrogen-7b46798c8e3b093a8591f25f66340e8f*.

[97] *omnigenglobal.com*.

[98] U.S. Energy Information Administration (EIA). (October 2023). Annual Coal Report 2022. *https://www.eia.gov/coal/annual/pdf/acr.pdf*.

[99] National Energy Technology Laboratory (NETL). Large Pilot Carbon Capture Project Supported by NETL Breaks Ground in Illinois. *https://netl.doe.gov/node/12284*.

suppliers to support additional future projects.[100]

In developing these final rules, the EPA reviewed the current state and cost of CCS technology for use with both steam generating units and stationary combustion turbines. This review is reflected in the respective BSER discussions later in this preamble and is further detailed in the accompanying RIA and final TSDs, *GHG Mitigation Measures for Steam Generating Units* and *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines.* These documents are included in the rulemaking docket.

2. Natural Gas Co-Firing

For a coal-fired steam generating unit, the substitution of natural gas for some of the coal so that the unit fires a combination of coal and natural gas is known as ''natural gas co-firing.'' Existing coal-fired steam generating units can be modified to co-fire natural gas in any desired proportion with coal. Generally, the modification of existing boilers to enable or increase natural gas firing involves the installation of new gas burners and related boiler modifications and may involve the construction of a natural gas supply pipeline if one does not already exist. In recent years, the cost of natural gas co-firing has declined because the expected difference between coal and gas prices has decreased and analysis supports lower capital costs for modifying existing boilers to co-fire with natural gas, as discussed in section VII.C.2.a of this preamble.

It is common practice for steam generating units to have the capability to burn multiple fuels onsite, and of the 565 coal-fired steam generating units operating at the end of 2021, 249 of them reported use of natural gas as a primary fuel or for startup.[101] Based on hourly reported CO_2 emission rates from the start of 2015 through the end of 2020, 29 coal-fired steam generating units co-fired with natural gas at rates at or above 60 percent of capacity on an hourly basis.[102] The capability of those units on an hourly basis is indicative of the extent of boiler burner modifications and sizing and capacity of natural gas pipelines to those units, and it implies that those units are technically capable of co-firing at least 60 percent natural gas on a heat input basis on average over the course of an extended period (*e.g.,* a year). Additionally, many coal-fired steam generating EGUs have also opted to switch entirely to providing generation from the firing of natural gas. Since 2011, more than 80 coal-fired utility boilers have been converted to natural gas-fired utility boilers.[103]

In developing these final actions, the EPA reviewed in detail the current state of natural gas co-firing technology and costs. This review is reflected in the BSER discussions later in this preamble and is further detailed in the accompanying RIA and final TSD, *GHG Mitigation Measures for Steam Generating Units.* Both documents are included in the rulemaking docket.

3. Efficient Generation

Highly efficient generation is the BSER technology upon which the first phase standards of performance are based for certain new and reconstructed stationary combustion turbine EGUs. This technology is available for both simple cycle and combined cycle combustion turbines and has been demonstrated—along with best operating and maintenance practices—to reduce emissions. Generally, as the thermal efficiency of a combustion turbine increases, less fuel is burned per gross MWh of electricity produced and there is a corresponding decrease in CO_2 and other air emissions.

For simple cycle turbines, manufacturers continue to improve the efficiency by increasing firing temperature, increasing pressure ratios, using intercooling on the air compressor, and adopting other measures. Best operating practices for simple cycle turbines include proper maintenance of the combustion turbine flow path components and the use of inlet air cooling to reduce efficiency losses during periods of high ambient temperatures. For combined cycle turbines, a highly efficient combustion turbine engine is matched with a high-efficiency HRSG. High efficiency also includes, but is not limited to, the use of the most efficient steam turbine and minimizing energy losses using insulation and blowdown heat recovery. Best operating and maintenance practices include, but are not limited to, minimizing steam leaks, minimizing air infiltration, and cleaning and maintaining heat transfer surfaces.

As discussed in section VIII.F.2.b of this preamble, efficient generation technologies have been in use at facilities in the power sector for decades and the levels of efficiency that the EPA is finalizing in this rule have been achieved by many recently constructed turbines. The efficiency improvements are incremental in nature and do not change how the combustion turbine is operated or maintained and present little incremental capital or compliance costs compared to other types of technologies that may be considered for new and reconstructed sources. In addition, more efficient designs have lower fuel costs, which offset at least a portion of the increase in capital costs. For additional discussion of this BSER technology, see the final TSD, *Efficient Generation in Combustion Turbines* in the docket for this rulemaking.

Efficiency improvements are also available for fossil fuel-fired steam generating units, and as discussed further in section VII.D.4.a, the more efficiently an EGU operates the less fuel it consumes, thereby emitting lower amounts of CO_2 and other air pollutants per MWh generated. Efficiency improvements for steam generating EGUs include a variety of technology upgrades and operating practices that may achieve CO_2 emission rate reductions of 0.1 to 5 percent for individual EGUs. These reductions are small relative to the reductions that are achievable from natural gas co-firing and from CCS. Also, as efficiency increases, some facilities could increase their utilization and therefore increase their CO_2 emissions (as well as emissions of other air pollutants). This phenomenon is known as the ''rebound effect.'' Because of this potential for perverse GHG emission outcomes resulting from deployment of efficiency measures at certain steam generating units, coupled with the relatively minor overall GHG emission reductions that would be expected, the EPA is not finalizing efficiency improvements as the BSER for any subcategory of existing coal-fired steam generating units. Specific details of efficiency measures are described in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* and an updated 2023 Sargent and Lundy HRI report (*Heat Rate Improvement Method Costs and Limitations Memo*), available in the docket.

[100] Net Power. (March 11, 2024). Q4 2023 Business Update and Results. *https://d1io3yog0oux5.cloudfront.net/cde4aad258e20f5aec49abd8654499f8/netpower/db/3583/33195/pdf/Q4_2023+Earnings+Presentation_3.11.24.pdf.*

[101] U.S. Energy Information Administration (EIA). Form 923. *https://www.eia.gov/electricity/data/eia923/.*

[102] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. *https://campd.epa.gov.*

[103] U.S. Energy Information Administration (EIA). (5 August 2020). Today in Energy. More than 100 coal-fired plants have been replaced or converted to natural gas since 2011. *https://www.eia.gov/todayinenergy/detail.php?id=44636.*

D. The Electric Power Sector: Trends and Current Structure

1. Overview

The electric power sector is experiencing a prolonged period of transition and structural change. Since the generation of electricity from coal-fired power plants peaked nearly two decades ago, the power sector has changed at a rapid pace. Today, natural gas-fired power plants provide the largest share of net generation, coal-fired power plants provide a significantly smaller share than in the recent past, renewable energy provides a steadily increasing share, and as new technologies enter the marketplace, power producers continue to replace aging assets—especially coal-fired power plants—with more efficient and lower-cost alternatives.

These developments have significant implications for the types of controls that the EPA determined to qualify as the BSER for different types of fossil fuel-fired EGUs. For example, power plant owners and operators retired an average annual coal-fired EGU capacity of 10 GW from 2015 to 2023, and coal-fired EGUs comprised 58 percent of all retired capacity in 2023.[104] While use of CCS promises significant emissions reduction from fossil fuel-fired sources, it requires substantial up-front capital expenditure. Therefore, it is not a feasible or cost-reasonable emission reduction technology for units that intend to cease operation before they would be able to amortize its costs. Industry stakeholders requested that the EPA structure these rules to avoid imposing costly control obligations on coal-fired power plants that have announced plans to voluntarily cease operations, and the EPA has determined the BSER in accordance with its understanding of which coal-fired units will be able to feasibly and cost-effectively deploy the BSER technologies. In addition, the EPA recognizes that utilities and power plant operators are building new natural gas-fired combustion turbines with plans to operate them at varying levels of utilization, in coordination with other existing and expected new energy sources. These patterns of operation are important for the type of controls that the EPA is finalizing as the BSER for these turbines.

2. Broad Trends Within the Power Sector

For more than a decade, the power sector has been experiencing substantial transition and structural change, both in terms of the mix of generating capacity and in the share of electricity generation supplied by different types of EGUs. These changes are the result of multiple factors, including normal replacements of older EGUs; technological improvements in electricity generation from both existing and new EGUs; changes in the prices and availability of different fuels; state and Federal policy; the preferences and purchasing behaviors of end-use electricity consumers; and substantial growth in electricity generation from renewable sources.

One of the most important developments of this transition has been the evolving economics of the power sector. Specifically, as discussed in section IV.D.3.b of this preamble and in the final TSD, *Power Sector Trends,* the existing fleet of coal-fired EGUs continues to age and become more costly to maintain and operate. At the same time, natural gas prices have held relatively low due to increased supply, and renewable costs have fallen rapidly with technological improvement and growing scale. Natural gas surpassed coal in monthly net electricity generation for the first time in April 2015, and since that time natural gas has maintained its position as the primary fuel for base load electricity generation, for peaking applications, and for balancing renewable generation.[105] In 2023, generation from natural gas was more than 2.5 times as much as generation from coal.[106] Additionally, there has been increased generation from investments in zero- and low-GHG emission energy technologies spurred by technological advancements, declining costs, state and Federal policies, and most recently, the IIJA and the IRA. For example, the IIJA provides investments and other policies to help commercialize, demonstrate, and deploy technologies such as small modular nuclear reactors, long-duration energy storage, regional clean hydrogen hubs, CCS and associated infrastructure, advanced geothermal systems, and advanced distributed energy resources (DER) as well as more traditional wind, solar, and battery energy storage resources. The IRA provides numerous tax and other incentives to directly spur deployment of clean energy technologies. Particularly relevant to these final actions, the incentives in the IRA,[107] [108] which are discussed in detail later in this section of the preamble, support the expansion of technologies, such as CCS, that reduce GHG emissions from fossil-fired EGUs.

The ongoing transition of the power sector is illustrated by a comparison of data between 2007 and 2022. In 2007, the year of peak coal generation, approximately 72 percent of the electricity provided to the U.S. grid was produced through the combustion of fossil fuels, primarily coal and natural gas, with coal accounting for the largest single share. By 2022, fossil fuel net generation was approximately 60 percent, less than the share in 2007 despite electricity demand remaining relatively flat over this same period. Moreover, the share of generation supplied by coal-fired EGUs fell from 49 percent in 2007 to 19 percent in 2022 while the share supplied by natural gas-fired EGUs rose from 22 to 39 percent during the same period. In absolute terms, coal-fired generation declined by 59 percent while natural gas-fired generation increased by 88 percent. This reflects both the increase in natural gas capacity as well as an increase in the utilization of new and existing natural gas-fired EGUs. The combination of wind and solar generation also grew from 1 percent of the electric power sector mix in 2007 to 15 percent in 2022.[109]

Additional analysis of the utility power sector, including projections of future power sector behavior and the impacts of these final rules, is discussed in more detail in section XII of this preamble, in the accompanying RIA, and in the final TSD, *Power Sector Trends.* The latter two documents are available in the rulemaking docket. Consistent with analyses done by other energy modelers, the information

[104] U.S. Energy Information Administration (EIA). (7 February 2023). Today in Energy. Coal and natural gas plants will account for 98 percent of U.S. capacity retirements in 2023. *https://www.eia.gov/todayinenergy/detail.php?id=55439.*

[105] U.S. Energy Information Administration (EIA). Monthly Energy Review and Short-Term Energy Outlook, March 2016. *https://www.eia.gov/todayinenergy/detail.php?id=25392.*

[106] U.S. Energy Information Administration (EIA). Electric Power Monthly, March 2024. *https://www.eia.gov/electricity/monthly/current_month/march2024.pdf.*

[107] U.S. Department of Energy (DOE). August 2022. *The Inflation Reduction Act Drives Significant Emissions Reductions and Positions America to Reach Our Climate Goals. https://www.energy.gov/sites/default/files/2022-08/8.18%20InflationReductionAct_Factsheet_Final.pdf.*

[108] U.S. Department of Energy (DOE). August 2023. Investing in American Energy. Significant Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Energy Economy and Emissions Reductions. *https://www.energy.gov/sites/default/files/2023-08/DOE%20OP%20Economy%20Wide%20Report_0.pdf.*

[109] U.S. Energy Information Administration (EIA). *Annual Energy Review,* table 8.2b Electricity net generation: electric power sector. *https://www.eia.gov/totalenergy/data/annual/.*

provided in the RIA and TSD demonstrates that the sector trend of moving away from coal-fired generation is likely to continue, the share from natural gas-fired generation is projected to decline eventually, and the share of generation from non-emitting technologies is likely to continue increasing. For instance, according to the Energy Information Administration (EIA), the net change in solar capacity has been larger than the net change in capacity for any other source of electricity for every year since 2020. In 2024, EIA projects that the actual increase in generation from solar will exceed every other source of generating capacity. This is in part because of the large amounts of new solar coming online in 2024 but is also due to the large amount of energy storage coming online, which will help reduce renewable curtailments.[110] EIA also projects that in 2024, the U.S. will see its largest year for installation of both solar and battery storage. Specifically, EIA projects that 36.4 GW of solar will be added, nearly doubling last year's record of 18.4 GW. Similarly, EIA projects 14.3 GW of new energy storage. This would more than double last year's record installation of 6.4 GW and nearly double the existing total capacity of 15.5 GW. This compares to only 2.5 GW of new natural gas turbine capacity.[111] The only year since 2013 when renewable generation did not make up the majority of new generation capacity in the U.S. was 2018.[112]

3. Coal-Fired Generation: Historical Trends and Current Structure

a. Historical Trends in Coal-Fired Generation

Coal-fired steam generating units have historically been the nation's foremost source of electricity, but coal-fired generation has declined steadily since its peak approximately 20 years ago.[113] Construction of new coal-fired steam generating units was at its highest between 1967 and 1986, with approximately 188 GW (or 9.4 GW per year) of capacity added to the grid during that 20-year period.[114] The peak annual capacity addition was 14 GW, which was added in 1980. These coal-fired steam generating units operated as base load units for decades. However, beginning in 2005, the U.S. power sector—and especially the coal-fired fleet—began experiencing a period of transition that continues today. Many of the older coal-fired steam generating units built in the 1960s, 1970s, and 1980s have retired or have experienced significant reductions in net generation due to cost pressures and other factors. Some of these coal-fired steam generating units repowered with combustion turbines and natural gas.[115] With no new coal-fired steam generating units larger than 25 MW commencing construction in the past decade—and with the EPA unaware of any plans being approved to construct a new coal-fired EGU—much of the fleet that remains is aging, expensive to operate and maintain, and increasingly uncompetitive relative to other sources of generation in many parts of the country.

Since 2007, the power sector's total installed net summer capacity[116] has increased by 167 GW (17 percent) while coal-fired steam generating unit capacity has declined by 123 GW.[117] This reduction in coal-fired steam generating unit capacity was offset by a net increase in total installed wind capacity of 125 GW, net natural gas capacity of 110 GW, and a net increase in utility-scale solar capacity of 71 GW during the same period. Additionally, significant amounts (40 GW) of DER solar were also added. At least half of these changes were in the most recent 7 years of this period. From 2015 to 2022, coal capacity was reduced by 90 GW and this reduction in capacity was offset by a net increase of 69 GW of wind capacity, 63 GW of natural gas capacity, and 59 GW of utility-scale solar capacity. Additionally, a net summer capacity of 30 GW of DER solar were added from 2015 to 2022.

b. Current Structure of Coal-Fired Generation

Although much of the fleet of coal-fired steam generating units has historically operated as base load, there can be notable differences in design and operation across various facilities. For example, coal-fired steam generating units smaller than 100 MW comprise 18 percent of the total number of coal-fired units, but only 2 percent of total coal-fired capacity.[118] Moreover, average annual capacity factors for coal-fired steam generating units have declined from 74 to 50 percent since 2007.[119] These declining capacity factors indicate that a larger share of units are operating in non-base load fashion largely because they are no longer cost-competitive in many hours of the year.

Older power plants also tend to become uneconomic over time as they become more costly to maintain and operate,[120] especially when competing for dispatch against newer and more efficient generating technologies that have lower operating costs. The average coal-fired power plant that retired between 2015 and 2022 was more than 50 years old, and 65 percent of the remaining fleet of coal-fired steam generating units will be 50 years old or more within a decade.[121] To further illustrate this trend, the existing coal-fired steam generating units older than 40 years represent 71 percent (129 GW)[122] of the total remaining capacity. In fact, more than half (100 GW) of the coal-fired steam generating units still operating have already announced retirement dates prior to 2039 or conversion to gas-fired units by the

[110] U.S. Energy Information Administration (EIA). Short Term Energy Outlook, December 2023.

[111] U.S. Energy Information Administration (EIA). (February 15, 2024). Today in Energy. *Solar and Battery Storage to make up 81% of new U.S. Electric-generating capacity in 2024. https://www.eia.gov/todayinenergy/detail.php?id=61424.*

[112] U.S. Energy Information Administration (EIA). Today in Energy. *Natural gas and renewables make up most of 2018 electric capacity additions. https://www.eia.gov/todayinenergy/detail.php?id=36092.*

[113] U.S. Energy Information Administration (EIA). Today in Energy. *Natural gas expected to surpass coal in mix of fuel used for U.S. power generation in 2016.* March 2016. *https://www.eia.gov/todayinenergy/detail.php?id=25392.*

[114] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form EIA–860M, Inventory of Operating Generators and Inventory of Retired Generators, March 2022. *https://www.eia.gov/electricity/data/eia860m/.*

[115] U.S. Energy Information Administration (EIA). Today in Energy. *More than 100 coal-fired plants have been replaced or converted to natural gas since 2011.* August 2020. *https://www.eia.gov/todayinenergy/detail.php?id=44636.*

[116] This includes generating capacity at EGUs primarily operated to supply electricity to the grid and combined heat and power (CHP) facilities classified as Independent Power Producers and excludes generating capacity at commercial and industrial facilities that does not operate primarily as an EGU. Natural gas information reflects data for all generating units using natural gas as the primary fossil heat source unless otherwise stated. This includes combined cycle, simple cycle, steam, and miscellaneous (<1 percent).

[117] U.S. Energy Information Administration (EIA). Electric Power Annuals 2010 (Tables 1.1.A and 1.1.B) and 2022 (Tables 4.2.A and 4.2.B).

[118] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[119] U.S. Energy Information Administration (EIA). Electric Power Annual 2021, table 1.2.

[120] U.S. Energy Information Administration (EIA). U.S. coal plant retirements linked to plants with higher operating costs. December 2019. *https://www.eia.gov/todayinenergy/detail.php?id=42155.*

[121] eGRID 2020 (January 2022 release from EPA eGRID website). Represents data from generators that came online between 1950 and 2020 (inclusive); a 71-year period. Full eGRID data includes generators that came online as far back as 1915.

[122] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form–860M, Inventory of Operating Generators and Inventory of Retired Generators. August 2022. *https://www.eia.gov/electricity/data/eia860m/.*

same year.[123] As discussed later in this section, projections anticipate that this trend will continue.

The reduction in coal-fired generation by electric utilities is also evident in data for annual U.S. coal production, which reflects reductions in international demand as well. In 2008, annual coal production peaked at nearly 1,172 million short tons (MMst) followed by sharp declines in 2015 and 2020.[124] In 2015, less than 900 MMst were produced, and in 2020, the total dropped to 535 MMst, the lowest output since 1965. Following the pandemic, in 2022, annual coal production had increased to 594 MMst. For additional analysis of the coal-fired steam generation fleet, see the final TSD, *Power Sector Trends* included in the docket for this rulemaking.

Notwithstanding these trends, in 2022, coal-fired energy sources were still responsible for 50 percent of CO_2 emissions from the electric power sector.[125]

4. Natural Gas-Fired Generation: Historical Trends and Current Structure

a. Historical Trends in Natural Gas-Fired Generation

There has been significant expansion of the natural gas-fired EGU fleet since 2000, coinciding with efficiency improvements of combustion turbine technologies, increased availability of natural gas, increased demand for flexible generation to support the expanding capacity of variable energy resources, and declining costs for all three elements. According to data from EIA, annual capacity additions for natural gas-fired EGUs peaked between 2000 and 2006, with more than 212 GW added to the grid during this period (about 35 GW per year). Of this total, approximately 147 GW (70 percent) were combined cycle capacity and 65 GW were simple cycle capacity.[126] From 2007 to 2022, more than 132 GW of capacity were constructed and approximately 77 percent of that total were combined cycle EGUs. This figure represents an average of almost 8.8 GW of new combustion turbine generation capacity per year. In 2022, the net summer capacity of combustion turbine EGUs totaled 419 GW, with 289 GW being combined cycle generation and 130 GW being simple cycle generation.

This trend away from electricity generation using coal-fired EGUs to natural gas-fired turbine EGUs is also reflected in comparisons of annual capacity factors, sizes, and ages of affected EGUs. For example, the average annual capacity factors for natural gas-fired units increased from 28 to 38 percent between 2010 and 2022. And compared with the fleet of coal-fired steam generating units, the natural gas fleet is generally smaller and newer. While 67 percent of the coal-fired steam generating unit fleet capacity is over 500 MW per unit, 75 percent of the gas fleet is between 50 and 500 MW per unit. In terms of the age of the generating units, nearly 50 percent of the natural gas capacity has been in service less than 15 years.[127]

b. Current Structure of Natural Gas-Fired Generation

In the lower 48 states, most combustion turbine EGUs burn natural gas, and some have the capability to fire distillate oil as backup for periods when natural gas is not available, such as when residential demand for natural gas is high during the winter. Areas of the country without access to natural gas often use distillate oil or some other locally available fuel. Combustion turbines have the capability to burn either gaseous or liquid fossil fuels, including but not limited to kerosene, naphtha, synthetic gas, biogases, liquified natural gas (LNG), and hydrogen.

Over the past 20 years, advances in hydraulic fracturing (*i.e.,* fracking) and horizontal drilling techniques have opened new regions of the U.S. to gas exploration. As the production of natural gas has increased, the annual average price has declined during the same period, leading to more natural gas-fired combustion turbines.[128] Natural gas net generation increased 181 percent in the past two decades, from 601 thousand gigawatt-hours (GWh) in 2000 to 1,687 thousand GWh in 2022. For additional analysis of natural gas-fired generation, see the final TSD, *Power Sector Trends* included in the docket for this rulemaking.

E. The Legislative, Market, and State Law Context

1. Recent Legislation Impacting the Power Sector

On November 15, 2021, President Biden signed the IIJA [129] (also known as the Bipartisan Infrastructure Law), which allocated more than $65 billion in funding via grant programs, contracts, cooperative agreements, credit allocations, and other mechanisms to develop and upgrade infrastructure and expand access to clean energy technologies. Specific objectives of the legislation are to improve the nation's electricity transmission capacity, pipeline infrastructure, and increase the availability of low-GHG fuels. Some of the IIJA programs [130] that will impact the utility power sector include more than $20 billion to build and upgrade the nation's electric grid, up to $6 billion in financial support for existing nuclear reactors that are at risk of closing, and more than $700 million for upgrades to the existing hydroelectric fleet. The IIJA established the Carbon Dioxide Transportation Infrastructure Finance and Innovation Program to provide flexible Federal loans and grants for building CO_2 pipelines designed with excess capacity, enabling integrated carbon capture and geologic storage. The IIJA also allocated $21.5 billion to fund new programs to support the development, demonstration, and deployment of clean energy technologies, such as $8 billion for the development of regional clean hydrogen hubs and $7 billion for the development of carbon management technologies, including regional direct air capture hubs, carbon capture large-scale pilot projects for development of transformational technologies, and carbon capture commercial-scale demonstration projects to improve efficiency and effectiveness. Other clean energy technologies with IIJA and IRA funding include industrial demonstrations, geologic sequestration, grid-scale energy storage, and advanced nuclear reactors.

The IRA, which President Biden signed on August 16, 2022,[131] has the potential for even greater impacts on the electric power sector. Energy Security and Climate Change programs in the

[123] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v6. October 2022. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[124] U.S. Energy Information Administration (EIA). (October 2023). Annual Coal Report 2022. *https://www.eia.gov/coal/annual/pdf/acr.pdf.*

[125] U.S. Energy Information Administration (EIA). U.S. CO_2 emissions from energy consumption by source and sector, 2022. *https://www.eia.gov/totalenergy/data/monthly/pdf/flow/CO2_emissions_2022.pdf.*

[126] U.S. Energy Information Administration (EIA). Electric Generators Inventory, Form EIA–860M, Inventory of Operating Generators and Inventory of Retired Generators, July 2022. *https://www.eia.gov/electricity/data/eia860m/.*

[127] National Electric Energy Data System (NEEDS) v.6.

[128] U.S. Energy Information Administration (EIA). *Natural Gas Annual,* September 2021. *https://www.eia.gov/energyexplained/natural-gas/prices.php.*

[129] *https://www.congress.gov/bill/117th-congress/house-bill/3684/text.*

[130] *https://www.whitehouse.gov/wp-content/uploads/2022/05/BUILDING-A-BETTER-AMERICA-V2.pdf.*

[131] *https://www.congress.gov/bill/117th-congress/house-bill/5376/text.*

IRA covering grant funding and tax incentives provide significant investments in low and non GHG-emitting generation. For example, one of the conditions set by Congress for the expiration of the Clean Electricity Production Tax Credits of the IRA, found in section 13701, is a 75 percent reduction in GHG emissions from the power sector below 2022 levels. The IRA also contains the Low Emission Electricity Program (LEEP) with funding provided to the EPA with the objective to reduce GHG emissions from domestic electricity generation and use through promotion of incentives, tools to facilitate action, and use of CAA regulatory authority. In particular, CAA section 135, added by IRA section 60107, requires the EPA to conduct an assessment of the GHG emission reductions expected to occur from changes in domestic electricity generation and use through fiscal year 2031 and, further, provides the EPA $18 million ''to ensure that reductions in [GHG] emissions are achieved through use of the existing authorities of [the Clean Air Act], incorporating the assessment. . . .'' CAA section 135(a)(6).

The IRA's provisions also demonstrate an intent to support development and deployment of low-GHG emitting technologies in the power sector through a broad array of additional tax credits, loan guarantees, and public investment programs. Particularly relevant for these final actions, these provisions are aimed at reducing emissions of GHGs from new and existing generating assets, with tax credits for CCUS and clean hydrogen production, providing a pathway for the use of coal and natural gas as part of a low-GHG electricity grid.

To assist states and utilities in their decarbonizing efforts, and most germane to these final actions, the IRA increased the tax credit incentives for capturing and storing CO_2, including from industrial sources, coal-fired steam generating units, and natural gas-fired stationary combustion turbines. The increase in credit values, found in section 13104 (which revises IRC section 45Q), is 70 percent, equaling $85/metric ton for CO_2 captured and securely stored in geologic formations and $60/metric ton for CO_2 captured and utilized or securely stored incidentally in conjunction with EOR.[132] The CCUS incentives include 12 years of credits that can be claimed at the higher credit value beginning in 2023 for qualifying projects. These incentives will significantly cut costs and are expected to accelerate the adoption of CCS in the utility power and other industrial sectors. Specifically for the power sector, the IRA requires that a qualifying carbon capture facility have a CO_2 capture design capacity of not less than 75 percent of the baseline CO_2 production of the unit and that construction must begin before January 1, 2033. Tax credits under IRC section 45Q can be combined with some other tax credits, in some circumstances, and with state-level incentives, including California's low carbon fuel standard, which is a market-based program with fuel-specific carbon intensity benchmarks.[133] The magnitude of this incentive is driving investment and announcements, evidenced by the increased number of permit applications for geologic sequestration.[134]

The new provisions in section 13204 (IRC section 45V) codify production tax credits for 'clean hydrogen' as defined in the provision. The value of the credits earned by a project is tiered (four different tiers) and depends on the estimated GHG emissions of the hydrogen production process as defined in the statute. The credits range from $3/kg H_2 for less than 0.45 kilograms of CO_2-equivalent emitted per kilogram of low-GHG hydrogen produced (kg CO_2e/kg H_2) down to $0.6/kg H_2 for 2.5 to 4.0 kg CO_2e/kg H_2 (assuming wage and apprenticeship requirements are met). Projects with production related GHG emissions greater than 4.0 kg CO_2e/kg H_2 are not eligible. Future costs for clean hydrogen produced using renewable energy are anticipated to through 2030 due to these tax incentives and concurrent scaling up of manufacturing and deployment of clean hydrogen production facilities.

Both IRC section 45Q and IRC section 45V are eligible for additional provisions that increase the value and usability of the credits. Certain tax-exempt entities, such as electric co-operatives, may elect direct payment for the full 12- or 10-year lifetime of the credits to monetize the credits directly as cash refunds rather than through tax equity transactions. Tax-paying entities may elect to have direct payment of IRC section 45Q or 45V credits for 5 consecutive years. Tax-paying entities may also elect to transfer credits to unrelated taxpayers, enabling direct monetization of the credits again without relying on tax equity transactions.

In addition to provisions such as 45Q that allow for the use of fossil-generating assets in a low-GHG future, the IRA also includes significant incentives to deploy clean energy generation. For instance, the IRA provides an additional 10 percent in production tax credit (PTC) and investment tax credit (ITC) bonuses for clean energy projects located in energy communities with historic employment and tax bases related to fossil fuels.[135] The IRA's Energy Infrastructure Reinvestment Program also provides $250 billion for the DOE to finance loan guarantees that can be used to reduce both the cost of retiring existing fossil assets and of replacement generation for those assets, including updating operating energy infrastructure with emissions control technologies.[136] As a further example, the Empowering Rural America (New ERA) Program provides rural electric cooperatives with funds that can be used for a variety of purposes, including ''funding for renewable and zero emissions energy systems that eliminate aging, obsolete or expensive infrastructure'' or that allow rural cooperatives to ''change [their] purchased-power mixes to support cleaner portfolios, manage stranded assets and boost [the] transition to clean energy.'' [137] The $9.7 billion New ERA program represents the single largest investment in rural energy systems since the Rural Electrification Act of 1936.[138]

On September 12, 2023, the EPA released a report assessing the impact of the IRA on the power sector. Modeling results showed that economy-wide CO_2 emissions are lower under the IRA. The

[132] 26 U.S.C. 45Q. Note, qualified facilities must meet prevailing wage and apprenticeship requirements to be eligible for the full value of the tax credit.

[133] Global CCS Institute. (2019). *The LCFS and CCS Protocol: An Overview for Policymakers and Project Developers.* Policy report. *https://www.globalccsinstitute.com/wp-content/uploads/2019/05/LCFS-and-CCS-Protocol_digital_version-2.pdf.*

[134] EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[135] U.S. Department of the Treasury. (April 4, 2023). Treasury Releases Guidance to Drive Investment to Coal Communities. Press release. *https://home.treasury.gov/news/press-releases/jy1383.*

[136] Fong, C., Posner, D., Varadarajan, U. (February 16, 2024). The Energy Infrastructure Reinvestment Program: Federal financing for an equitable, clean economy. Case studies from Missouri and Iowa. Rocky Mountain Institute (RMI). *https://rmi.org/the-energy-infrastructure-reinvestment-program-federal-financing-for-an-equitable-clean-economy/.*

[137] U.S. Department of Agriculture (USDA). Empowering Rural America New ERA Program. *https://www.rd.usda.gov/programs-services/electric-programs/empowering-rural-america-new-era-program.*

[138] Rocky Mountain Institute (RMI). (October 4, 2023). USDA $9.7B Rural Community Clean Energy Program Receives 150+ Letters of Interest. Press release. *https://rmi.org/press-release/usda-9-7b-rural-community-clean-energy-program-receives-150-letters-of-interest/.*

results from the EPA's analysis of an array of multi-sector and electric sector modeling efforts show that a wide range of emissions reductions are possible. The IRA spurs CO_2 emissions reductions from the electric power sector of 49 to 83 percent below 2005 levels in 2030. This finding reflects diversity in how the models represent the IRA, the assumptions the models use, and fundamental differences in model structures.[139]

In determining the CAA section 111 emission limitations that are included in these final actions, the EPA did not consider many of the technologies that receive investment under recent Federal legislation. The EPA's determination of the BSER focused on ''measures that improve the pollution performance of individual sources,'' [140] not generation technologies that entities could employ as alternatives to fossil fuel-fired EGUs. However, these overarching incentives and policies are important context for this rulemaking and influence where control technologies can be feasibly and cost-reasonably deployed, as well as how owners and operators of EGUs may respond to the requirements of these final actions.

2. Commitments by Utilities To Reduce GHG Emissions

Integrated resource plans (IRPs) are filed by public utilities and demonstrate how utilities plan to meet future forecasted energy demand while ensuring reliable and cost-effective service. In developing these rules, the EPA reviewed filed IRPs of companies that have publicly committed to reducing their GHGs. These IRPs demonstrate a range of strategies that public utilities are planning to adopt to reduce their GHGs, independent of these final actions. These strategies include retiring aging coal-fired steam generating EGUs and replacing them with a combination of renewable resources, energy storage, other non-emitting technologies, and natural gas-fired combustion turbines, and reducing GHGs from their natural gas-fired assets through a combination of CCS and reduced utilization. To affirm these findings, according to EIA, as of 2022 there are no new coal-fired EGUs in development. This section highlights recent actions and announced plans of many utilities across the industry to reduce GHGs from their fleets. Indeed, 50 power producers that are members of the Edison Electric Institute (EEI) have announced CO_2 reduction goals, two-thirds of which include net-zero carbon emissions by 2050.[141] The members of the Energy Strategies Coalition, a group of companies that operate and manage electricity generation facilities, as well as electricity and natural gas transmission and distribution systems, likewise are focused on investments to reduce carbon dioxide emissions from the electricity sector.[142] This trend is not unique. Smaller utilities, rural electric cooperatives, and municipal entities are also contributing to these changes.

Many electric utilities have publicly announced near- and long-term emission reduction commitments independent of these final actions. The Smart Electric Power Alliance demonstrates that the geographic footprint of commitments for 100 percent renewable, net-zero, or other carbon emission reductions by 2050 made by utilities, their parent companies, or in response to a state clean energy requirement, covers portions of 47 states and includes 80 percent of U.S. customer accounts.[143] According to this same source, 341 utilities in 26 states have similar commitments by 2040. Additional detail about emission reduction commitments from major utilities is provided in section 2.2 of the RIA and in the final TSD, *Power Sector Trends.*

3. State Actions To Reduce Power Sector GHG Emissions

States across the country have taken the lead in efforts to reduce GHG emissions from the power sector. As of mid-2023, 25 states had made commitments to reduce economy-wide GHG emissions consistent with the goals of the Paris Agreement, including reducing GHG emissions by 50 to 52 percent by 2030.[144] [145] [146] These actions include legislation to decarbonize state power systems as well as commitments that require utilities to expand renewable and clean energy production through the adoption of renewable portfolio standards (RPS) and clean energy standards (CES).

Several states have enacted binding economy-wide emission reduction targets that will require significant decarbonization from state power sectors, including California, Colorado, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, Vermont, and Washington.[147] These commitments are statutory emission reduction targets accompanied by mandatory agency directives to develop comprehensive implementing regulations to achieve the necessary reductions. Some of these states, along with other neighboring states, also participate in the Regional Greenhouse Gas Initiative (RGGI), a carbon market limiting pollution from power plants throughout New England.[148] The pollution limit combined with carbon price and allowance market has led member states to reduce power sector CO_2 emissions by nearly 50 percent since the start of the program in 2009. This is 10 percent more than all non-RGGI states.[149]

Other states dependent on coal-fired power generation or coal production also have significant, albeit non-

[139] U.S. Environmental Protection Agency (EPA). (September 2023). *Electricity Sector Emissions Impacts of the Inflation Reduction Act. https://www.epa.gov/system/files/documents/2023-09/Electricity_Emissions_Impacts_Inflation_Reduction_Act_Report_EPA–FINAL.pdf.*

[140] *West Virginia* v. *EPA,* 597 U.S. at 734.

[141] See Comments of Edison Electric Institute to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants, Document ID No. EPA–HQ–OAR–2022–0723–0024, November 18, 2022 (''Fifty EEI members have announced forward-looking carbon reduction goals, two-third of which include a net-zero by 2050 or earlier equivalent goal, and members are routinely increasing the ambition or speed of their goals or altogether transforming them into net-zero goals.'').

[142] Energy Strategy Coalition Comments on EPA's proposed New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, Document ID No. EPA–HQ–OAR–2023–0072–0672, August 14, 2023.

[143] Smart Electric Power Alliance Utility Carbon Tracker. *https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker/.*

[144] Cao, L., Brindle., T., Schneer, K., and DeGolia, A. (December 2023). Turning Climate Commitments into Results: Evaluating Updated 2023 Projections vs. State Climate Targets. Environmental Defense Fund (EDF). *https://www.edf.org/sites/default/files/2023–11/EDF-State-Emissions-Gap-December-2023.pdf.*

[145] United Nations Framework Convention on Climate Change. What is the Paris Agreement? *https://unfccc.int/process-and-meetings/the-paris-agreement.*

[146] U.S. Department of State and U.S. Executive Office of the President. November 2021. The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050. *https://www.whitehouse.gov/wp-content/uploads/2021/10/us-long-term-strategy.pdf.*

[147] Cao, L., Brindle., T., Schneer, K., and DeGolia, A., December 2023. Turning Climate Commitments into Results: Evaluating Updated 2023 Projections vs. State Climate Targets. Environmental Defense Fund (EDF). *https://www.edf.org/sites/default/files/2023-11/EDF-State-Emissions-Gap-December-2023.pdf.*

[148] A full list of states currently participating in RGGI include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

[149] Note that these figures do not include Virginia and Pennsylvania, which were not members of RGGI for the full duration of 2009–2023. Acadia Center: Regional Greenhouse Gas Initiative; Findings and Recommendations for the Third Program Review. *https://acadiacenter.wpengine powered.com/wp-content/uploads/2023/04/AC_RGGI_2023_Layout_R6.pdf.*

binding, commitments that signal broad public support for policy with emissions-based metrics and public affirmation that climate change is fundamentally linked to fossil-intensive energy sources. These states include Illinois, Michigan, Minnesota, New Mexico, North Carolina, Pennsylvania, and Virginia. States like Wyoming, the top coal producing state in the U.S., have promulgated sector-specific regulations requiring their public service commissions to implement low-carbon energy standards for public utilities.[150] [151] Specific standards are further detailed in the sections that follow and in the final TSD, *Power Sector Trends.*

Technologies like CCS provide a means to achieve significant emission reduction targets. For example, to achieve GHG emission reduction goals legislatively enacted in 2016, California Senate Bill 100, passed in 2018, requires the state to procure 60 percent of all electricity from renewable sources by 2030 and plan for 100 percent from carbon-free sources by 2045.[152] Achieving California's established goal of carbon-free electricity by 2045 requires emissions to be balanced by carbon sequestration, capture, or other technologies. Therefore, California Senate Bill 905, passed in 2022, requires the California Air Resources Board (CARB) to establish programs for permitting CCS projects while preventing the use of captured CO_2 for EOR within the state.[153] As mentioned previously, as the top coal producing state, Wyoming has been exceptionally persistent on the implementation of CCS by incentivizing the national testing of CCS at Basin Electric's coal-fired Dry Fork Station[154] and by requiring the consideration of CCS as an alternative to coal plant retirement.[155] At least five other states, including Montana and North Dakota, also have tax incentives and regulations for CCS.[156] In the case of Montana, the acquisition of an equity interest or lease of coal-fired EGUs is prohibited unless it captures and stores at least 50 percent of its CO_2 emissions.[157] These state policies have coincided with the planning and development of large CCS projects.

Other states have broad decarbonization laws that will drive significant decrease in power sector GHG emissions. In New York, The Climate Leadership and Community Protection Act, passed in 2019, sets several climate targets. The most important goals include an 85 percent reduction in GHG emissions by 2050, 100 percent zero-emission electricity by 2040, and 70 percent renewable energy by 2030. Other targets include 9,000 MW of offshore wind by 2035, 3,000 MW of energy storage by 2030, and 6,000 MW of solar by 2025.[158] Washington State's Climate Commitment Act sets a target of reducing GHG emissions by 95 percent by 2050. The state is required to reduce emissions to 1990 levels by 2020, 45 percent below 1990 levels by 2030, 70 percent below 1990 levels by 2040, and 95 percent below 1990 levels by 2050. This also includes achieving net-zero emissions by 2050.[159] Illinois' Climate and Equitable Jobs Act, enacted in September 2021, requires all private coal-fired or oil-fired power plants to reach zero carbon emissions by 2030, municipal coal-fired plants to reach zero carbon emissions by 2045, and natural gas-fired plants to reach zero carbon emissions by 2045.[160] In October 2021, North Carolina passed House Bill 951 that required the North Carolina Utilities Commission to ''take all reasonable steps to achieve a seventy percent (70 percent) reduction in emissions of carbon dioxide (CO_2) emitted in the state from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050.'' [161]

The ambition and scope of these state power sector polices will impact the electric generation fleet for decades. Seven states with 100-percent power sector decarbonization polices include a total of 20 coal-fired EGUs with slightly less than 10 GW total capacity and without announced retirement dates before 2039.[162] Virginia, which has three coal-steam units with no announced retirement dates and one with a 2045 retirement date, enacted the Clean Economy Act in 2020 to impose a 100 percent RPS requirement by 2050. The combined capacity of all four of these units in Virginia totals nearly 1.5 GW. North Carolina, which has one coal-fired unit without an announced retirement date and one with a planned 2048 retirement, as previously mentioned, enacted a state law in 2021 requiring the state's utilities commission to achieve carbon neutrality by 2050. The combined capacity of both units totals approximately 1.4 GW of capacity. Nebraska, where three public utility boards serving a large portion of the state have adopted net-zero electricity emission goals by 2040 or 2050, includes six coal-fired units with a combined capacity of 2.9 GW. The remaining eight units are in states with long-term decarbonization goals (Illinois, Louisiana, Maryland, and Wisconsin). All four of these states have set 100 percent clean energy goals by 2050.

Twenty-nine states and the District of Columbia have enforceable RPS [163] that require a percentage of electricity that utilities sell to come from eligible renewable sources like wind and solar rather than from fossil fuel-based sources like coal and natural gas. Furthermore, 20 states have adopted a CES that includes some form of clean

[150] State of Wyoming. (Adopted March 24, 2020). House Bill 200 Reliable and dispatchable low-carbon energy standards. *https://www.wyoleg.gov/Legislation/2020/HB0200.*

[151] State of Wyoming. (Adopted March 15, 2024). Senate Bill 42 Low-carbon reliable energy standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042.*

[152] Berkeley Law. *California Climate Policy Dashboard. https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard.*

[153] Berkeley Law. *California Climate Policy Dashboard. https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard.*

[154] Basin Electric Power Cooperative. (May 2023). Press Release: Carbon Capture Technology Developers Break Ground at Wyoming Integrated Test Center Located at Basin Electric's Dry Fork Station. *https://www.basinelectric.com/News-Center/news-briefs/Carbon-capture-technology-developers-break-ground-at-Wyoming-Integrated-Test-Center-located-at-Basin-Electrics-Dry-Fork-Station.*

[155] State of Wyoming. (Adopted March 15, 2024). Senate Bill 42 Low-carbon reliable energy standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042.*

[156] Sabin Center for Climate Change Law. 2019. Legal Pathways to Deep Decarbonization. Interactive Tracker for State Action on Carbon Capture. *https://cdrlaw.org/ccus-tracker/.*

[157] Sabin Center for Climate Change Law. 2019. Legal Pathways to Deep Decarbonization. Model Laws. Montana prohibition on acquiring coal plants without CCS. *https://lpdd.org/resources/montana-prohibition-on-acquiring-coal-plants-without-ccs/.*

[158] New York State. Climate Act: Progress to our Goals. *https://climate.ny.gov/Our-Impact/Our-Progress.*

[159] Department of Ecology Washington State. *Greenhouse Gases. https://ecology.wa.gov/Air-Climate/Climate-change/Tracking-greenhouse-gases.*

[160] State of Illinois General Assembly. Public Act 102–0662: Climate and Equitable Jobs Act. 2021. *https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf.*

[161] General Assembly of North Carolina, House Bill 951 (2021). *https://www.ncleg.gov/Sessions/2021/Bills/House/PDF/H951v5.pdf.*

[162] These estimates are based on an analysis of the EPA's NEEDS database, which contains information about EGUs across the country. The analysis includes a basic screen for units within the NEEDS database that are likely subject to the final 111(d) EGU rule, namely coal-steam units with capacity greater than 25 MW, and then removes units with an announced retirement dates prior to 2039, units with announced plans to convert from coal- to gas-fired units, and units likely to fall outside of the rule's applicability via the cogeneration exemption.

[163] DSIRE, Renewable Portfolio Standards and Clean Energy Standards (2023). *https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2023/12/RPS-CES-Dec2023-1.pdf;* LBNL, *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update. https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean.*

energy requirement or goal with a 100 percent or net-zero target.[164] A CES shifts generating fleets away from fossil fuel resources by requiring a percentage of retail electricity to come from sources that are defined as clean. Unlike an RPS, which defines eligible generation in terms of the renewable attributes of its energy source, CES eligibility is based on the GHG emission attributes of the generation itself, typically with a zero or net-zero carbon emissions requirement. Additional discussion of state actions and legislation to reduce GHG emissions from the power sector is provided in the final TSD, *Power Sector Trends.*

F. Future Projections of Power Sector Trends

Projections for the U.S. power sector—based on the landscape of market forces in addition to the known actions of Congress, utilities, and states—have indicated that the ongoing transition will continue for specific fuel types and EGUs. The EPA's Power Sector Platform 2023 using IPM reference case (*i.e.,* the EPA's projections of the power sector, which includes representation of the IRA absent further regulation), provides projections out to 2050 on future outcomes of the electric power sector. For more information on the details of this modeling, see the model documentation.[165]

Since the passage of the IRA in August 2022, the EPA has engaged with many external partners, including other governmental entities, academia, non-governmental organizations (NGOs), and industry, to understand the impacts that the IRA will have on power sector GHG emissions. In addition to engaging in several workgroups, the EPA has contributed to two separate journal articles that include multi-model comparisons of IRA impacts across several state-of-the-art models of the U.S. energy system and electricity sector [166] [167] and participated in public events exploring modeling assumptions for the IRA.[168] The EPA plans to continue collaborating with stakeholders, conducting external engagements, and using information gathered to refine modeling of the IRA.

While much of the discussion below focuses on the EPA's Power Sector Platform 2023 using IPM reference case, many other analyses show similar trends,[169] and these trends are consistent with utility IRPs and public GHG reduction commitments, as well as state actions, both of which were described in the previous sections.

1. Future Projections for Coal-Fired Generation

As described in the EPA's baseline modeling, coal-fired steam generating unit capacity is projected to fall from 181 GW in 2023 [170] to 52 GW in 2035, of which 11 GW includes retrofit CCS. Generation from coal-fired steam generating units is projected to also fall from 898 thousand GWh in 2021 [171] to 236 thousand GWh by 2035. This change in generation reflects the anticipated continued decline in projected coal-fired steam generating unit capacity as well as a steady decline in annual operation of those EGUs that remain online, with capacity factors falling from approximately 48 percent in 2022 to 45 percent in 2035 at facilities that do not install CCS. By 2050, coal-fired steam generating unit capacity is projected to diminish further, with only 28 GW, or less than 16 percent of 2023 capacity (and approximately 9 percent of the 2010 capacity), still in operation across the continental U.S.

These projections are driven by the eroding economic opportunities for coal-fired steam generating units to operate, the continued aging of the fleet of coal-fired steam generating units, and the continued availability and expansion of low-cost alternatives, like natural gas, renewable technologies, and energy storage. The projected retirements continue the trend of coal plant retirements in recent decades that is described in section IV.D.3. of this preamble (and further in the *Power Sector Trends* technical support document). The decline in coal generation capacity has generally resulted from a more competitive economic environment and increasing coal plant age. Most notably, declines in natural gas prices associated with the rise of hydraulic fracturing and horizontal drilling lowered the cost of natural gas-fired generation.[172] Lower gas generation costs reduced coal plant capacity factors and revenues. Rapid declines in the costs of renewables and battery storage have put further price pressure on coal plants, given the zero marginal cost operation of solar and wind.[173] [174] [175] In addition, most operational coal plants today were built before 2000, and many are reaching or have surpassed their expected useful lives.[176] Retiring coal plants tend to be

---

[164] This count is adapted from Lawrence Berkeley National Laboratory's (LBNL) *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update,* which identifies 15 states with 100 percent CES. The LBNL count includes Virginia, which the EPA omits because it considers Virginia a 100 percent RPS. Further, the LBNL count excludes Louisiana, Michigan, New Jersey, and Wisconsin because their clean energy goals are set by executive order. The EPA instead includes Louisiana, New Jersey, and Wisconsin but characterizes them as goals rather than requirements. Michigan, which enacted a CES by statute after the LBNL report's publication, is also included in the EPA count. Finally, the EPA count includes Maryland, whose December 2023 *Climate Pollution Reduction Plan* sets a goal of 100 percent clean energy by 2035, and Delaware, which enacted a statutory goal to reach net-zero GHG emissions by 2050. See LBNL, *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update, https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean*; *Maryland's Climate Pollution Reduction Plan, https://mde.maryland.gov/programs/air/ClimateChange/Maryland%20Climate%20Reduction%20Plan/Maryland%27s%20Climate%20Pollution%20Reduction%20Plan%20-%20Final%20-%20Dec%2028%202023.pdf*; and *HB 99, An Act to Amend Titles 7 and 29 of the Delaware Code Relating to Climate Change, https://legis.delaware.gov/json/BillDetail/GenerateHtmlDocumentEngrossment?engrossmentId=25785&docTypeId=6.*

[165] U.S. Environmental Protection Agency.*Power Sector Platform 2023 using IPM.* April 2024. *https://www.epa.gov/power-sector-modeling.*

[166] Bistline, *et al.* (2023). ''Emissions and Energy System Impacts of the Inflation Reduction Act of 2022.'' *https://www.science.org/stoken/author-tokens/ST-1277/full.*

[167] Bistline, *et al.* (2023). ''Power Sector Impacts of the Inflation Reduction Act of 2022.''*https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b.*

[168] Resource for the Future (2023). ''Future Generation: Exploring the New Baseline for Electricity in the Presence of the Inflation Reduction Act.'' *https://www.rff.org/events/rff-live/future-generation-exploring-the-new-baseline-for-electricity-in-the-presence-of-the-inflation-reduction-act/.*

[169] A wide variety of modeling teams have assessed baselines with IRA. The baseline estimated here is generally in line with these other estimates. Bistline, *et al.* (2023). ''Power Sector Impacts of the Inflation Reduction Act of 2022.'' *https://iopscience.iop.org/article/10.1088/1748-9326/ad0d3b.*

[170] U.S. Energy Information Administration (EIA), Preliminary Monthly Electric Generator Inventory, December 2023. *https://www.eia.gov/electricity/data/eia860m/*

[171] U.S. Energy Information Administration (EIA), Electric Power Annual, table 3.1.A. November 2022. *https://www.eia.gov/electricity/annual/.*

[172] International Energy Agency (IEA). Energy Policies of IEA Countries: United States 2019 Review. *https://iea.blob.core.windows.net/assets/7c65c270-ba15-466a-b50d-1c5cd19e359c/United_States_2019_Review.pdf.*

[173] U.S. Energy Information Administration (EIA). (April 13, 2023). U.S. Electric Capacity Mix shifts from Fossil Fuels to Renewables in AEO2023. *https://www.eia.gov/todayinenergy/detail.php?id=56160.*

[174] Solomon, M., et al. (January 2023). Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment. Energy Innovation. *https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.*

[175] Barbose, G., et al. (September 2023). Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, 2023 Edition. Lawrence Berkeley National Laboratory. *https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.*

[176] U.S. Energy Information Administration (EIA). (August 2022). Electric Generators Inventory, Form–860M, Inventory of Operating Generators and Inventory of Retired Generators. *https://www.eia.gov/electricity/data/eia860m/.*

old.[177] As plants age, their efficiency tends to decline and operations and maintenance costs increase. Older coal plant operational parameters are less aligned with current electric grid needs. Coal plants historically were used as base load power sources and can be slow (or expensive) to increase or decrease generation output throughout a typical day. That has put greater economic pressure on older coal plants, which are forced to either incur the costs of adjusting their generation or operate during less profitable hours when loads are lower or renewable generation is more plentiful.[178] All of these factors have contributed to retirements over the past 15 years, and similar underlying factors are projected to continue the trend of coal retirements in the coming years.

In 2020, there was a total of 1,439 million metric tons of CO_2 emissions from the power sector with coal-fired sources contributing to more than half of those emissions. In the EPA's Power Sector Platform 2023 using IPM reference case, power sector related CO_2 emission are projected to fall to 724 million metric tons by 2035, of which 23 percent is projected to come from coal-fired sources in 2035.

2. Future Projections for Natural Gas-Fired Generation

As described in the EPA's Power Sector Platform 2023 using IPM reference case, natural gas-fired capacity is expected to continue to build out during the next decade with 34 GW of new capacity projected to come online by 2035 and 261 GW of new capacity by 2050. By 2035, the new natural gas capacity is comprised of 14 GW of simple cycle turbines and 20 GW of combined cycle turbines. By 2050, most of the incremental new capacity is projected to come just from simple cycle turbines. This also represents a higher rate of new simple cycle turbine builds compared to the reference periods (*i.e.,* 2000–2006 and 2007–2021) discussed previously in this section.

It should be noted that despite this increase in capacity, both overall generation and emissions from the natural gas-fired capacity are projected to decline. Generation from natural gas units is projected to fall from 1,579 thousand GWh in 2021[179] to 1,344 thousand GWh by 2035. Power sector related CO_2 emissions from natural gas-fired EGUs were 615 million metric tons in 2021.[180] By 2035, emission levels are projected to reach 521 million metric tons, 96 percent of which comes from NGCC sources.

The decline in generation and emissions is driven by a projected decline in NGCC capacity factors. In model projections, NGCC units have a capacity factor early in the projection period of 59 percent, but by 2035, capacity factor projections fall to 48 percent as many of these units switch from base load operation to more intermediate load operation to support the integration of variable renewable energy resources. Natural gas-fired simple cycle turbine capacity factors also fall, although since they are used primarily as a peaking resource and their capacity factors are already below 10 percent annually, their impact on generation and emissions changes are less notable.

Some of the reasons for this anticipated continued growth in natural gas-fired capacity, coupled with a decline in generation and emissions, include the anticipated growth in peak load, retirement of older fossil generators, and growth in renewable energy coupled with the greater flexibility offered by combustion turbines. Simple cycle turbines operate at lower efficiencies than NGCC units but offer fast startup times to meet peaking load demands. In addition, combustion turbines, along with energy storage technologies and demand response strategies, support the expansion of renewable electricity by meeting demand during peak periods and providing flexibility around the variability of renewable generation and electricity demand. In the longer term, as renewables and battery storage grow, they are anticipated to outcompete the need for some natural gas-fired generation and the overall utilization of natural gas-fired capacity is expected to decline. For additional discussion and analysis of projections of future coal- and natural gas-fired generation, see the final TSD, *Power Sector Trends* in the docket for this rulemaking.

As explained in greater detail later in this preamble and in the accompanying RIA, future generation projections for natural gas-fired combustion turbines differ from those highlighted in recent historical trends. The largest source of new generation is from renewable energy, and projections show that total natural gas-fired combined cycle capacity is likely to decline after 2030 in response to increased generation from renewables, deployment of energy storage, and other technologies. Approximately 95 percent of capacity additions in 2024 are expected to be from non-emitting generation resources including solar, battery storage, wind, and nuclear.[181] The IRA is likely to influence this trend, which is also expected to impact the operation of certain combustion turbines. For example, as the electric output from additional variable renewable generating sources fluctuates daily and seasonally, flexible low and intermediate load combustion turbines will be needed to support these variable sources and provide reliability to the grid. This requires the ability to start and stop quickly and change load more frequently. Today's system includes 212 GW of intermediate and low load combustion turbines. These operational changes, alongside other tools like demand response, energy storage, and expanded transmission, will maintain reliability of the grid.

V. Statutory Background and Regulatory History for CAA Section 111

A. Statutory Authority To Regulate GHGs From EGUs Under CAA Section 111

The EPA's authority for and obligation to issue these final rules is CAA section 111, which establishes mechanisms for controlling emissions of air pollutants from new and existing stationary sources. CAA section 111(b)(1)(A) requires the EPA Administrator to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has the authority to define the scope of the source categories, determine the pollutants for which standards should be developed, and distinguish among classes, types, and sizes within categories in establishing the standards.

[177] Mills, A., et al. (November 2017). Power Plant Retirements: Trends and Possible Drivers. Lawrence Berkeley National Laboratory. *https://live-etabiblio.pantheonsite.io/sites/default/files/lbnl_retirements_data_synthesis_final.pdf.*

[178] National Association of Regulatory Utility Commissioners. (January 2020). Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices. *https://pubs.naruc.org/pub/7B762FE1-A71B-E947-04FB-D2154DE77D45.*

[179] U.S. Energy Information Administration (EIA), Electric Power Annual, table 3.1.A. November 2022. *https://www.eia.gov/electricity/annual/.*

[180] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emission Sources and Sinks. February 2023. *https://www.epa.gov/system/files/documents/2023-02/US-GHG-Inventory-2023-Main-Text.pdf.*

[181] U.S. Energy Information Administration (EIA). Today in Energy. Solar and battery storage to make up 81 percent of new U.S. electric-generating capacity in 2024. February 2024. *https://www.eia.gov/todayinenergy/detail.php?id=61424.*

1. Regulation of Emissions From New Sources

Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for ''new sources'' in the source category. These standards are referred to as new source performance standards, or NSPS. The NSPS are national requirements that apply directly to the sources subject to them.

Under CAA section 111(a)(1), a ''standard of performance'' is defined, in the singular, as ''a standard for emissions of air pollutants'' that is determined in a specified manner, as noted in this section, below.

Under CAA section 111(a)(2), a ''new source'' is defined, in the singular, as ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section, which will be applicable to such source.'' Under CAA section 111(a)(3), a ''stationary source'' is defined as ''any building, structure, facility, or installation which emits or may emit any air pollutant.'' Under CAA section 111(a)(4), ''modification'' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. While this provision treats modified sources as new sources, EPA regulations also treat a source that undergoes ''reconstruction'' as a new source. Under the provisions in 40 CFR 60.15, ''reconstruction'' means the replacement of components of an existing facility such that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards. Pursuant to CAA section 111(b)(1)(B), the standards of performance or revisions thereof shall become effective upon promulgation.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to reflect ''the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The term ''standard of performance'' in CAA 111(a)(1) makes clear that the EPA is to determine both the ''best system of emission reduction . . . adequately demonstrated'' (BSER) for the regulated sources in the source category and the ''degree of emission limitation achievable through the application of the [BSER].'' *West Virginia* v. *EPA,* 597 U.S. 697, 709 (2022). To determine the BSER, the EPA first identifies the ''system[s] of emission reduction'' that are ''adequately demonstrated,'' and then determines the ''best'' of those systems, ''taking into account'' factors including ''cost,'' ''nonair quality health and environmental impact,'' and ''energy requirements.'' The EPA then derives from that system an ''achievable'' ''degree of emission limitation.'' The EPA must then, under CAA section 111(b)(1)(B), promulgate ''standard[s] for emissions''—the NSPS—that reflect that level of stringency.

2. Regulation of Emissions From Existing Sources

When the EPA establishes a standard for emissions of an air pollutant from new sources within a category, it must also, under CAA section 111(d), regulate emissions of that pollutant from *existing* sources within the same category, unless the pollutant is regulated under the National Ambient Air Quality Standards (NAAQS) program, under CAA sections 108–110, or the National Emission Standards for Hazardous Air Pollutants (NESHAP) program, under CAA section 112. See CAA section 111(d)(1)(A)(i) and (ii); *West Virginia,* 597 U.S. at 710.

CAA section 111(d) establishes a framework of ''cooperative federalism for the regulation of existing sources.'' *American Lung Ass'n,* 985 F.3d at 931. CAA sections 111(d)(1)(A)–(B) require ''[t]he Administrator . . . to prescribe regulations'' that require ''[e]ach state . . . to submit to [EPA] a plan . . . which establishes standards of performance for any existing stationary source for'' the air pollutant at issue, and which ''provides for the implementation and enforcement of such standards of performance.'' CAA section 111(a)(6) defines an ''existing source'' as ''any stationary source other than a new source.''

To meet these requirements, the EPA promulgates ''emission guidelines'' that identify the BSER and the degree of emission limitation achievable through the application of the BSER. Each state must then establish standards of performance for its sources that reflect that level of stringency. However, the states need not compel regulated sources to adopt the particular components of the BSER itself. The EPA's emission guidelines must also permit a state, ''in applying a standard of performance to any particular source,'' to ''take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' 42 U.S.C. 7411(d)(1). Once a state receives the EPA's approval of its plan, the provisions in the plan become federally enforceable against the source, in the same manner as the provisions of an approved State Implementation Plan (SIP) under the Act. CAA section 111(d)(2)(B). If a state elects not to submit a plan or submits a plan that the EPA does not find ''satisfactory,'' the EPA must promulgate a plan that establishes Federal standards of performance for the state's existing sources. CAA section 111(d)(2)(A).

3. EPA Review of Requirements

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years, review and, if appropriate, revise'' new source performance standards. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. *Id.* When conducting a review of an NSPS, the EPA has the discretion and authority to add emission limits for pollutants or emission sources not currently regulated for that source category. CAA section 111 does not by its terms require the EPA to review emission guidelines for existing sources, but the EPA retains the authority to do so. See 81 FR 59277 (August 29, 2016) (explaining legal authority to review emission guidelines for municipal solid waste landfills).

B. History of EPA Regulation of Greenhouse Gases From Electricity Generating Units Under CAA Section 111 and Caselaw

The EPA has listed more than 60 stationary source categories under CAA section 111(b)(1)(A). See 40 CFR part 60, subparts Cb–OOOO. In 1971, the EPA listed fossil fuel-fired EGUs (which includes natural gas, petroleum, and coal) that use steam-generating boilers in a category under CAA section 111(b)(1)(A). See 36 FR 5931 (March 31, 1971) (listing ''fossil fuel-fired steam generators of more than 250 million Btu per hour heat input''). In 1977, the EPA listed fossil fuel-fired combustion turbines, which can be used in EGUs, in a category under CAA section 111(b)(1)(A). See 42 FR 53657 (October 3, 1977) (listing ''stationary gas turbines'').

Beginning in 2007, several decisions by the U.S. Supreme Court and the D.C. Circuit have made clear that under CAA section 111, the EPA has authority to regulate GHG emissions from listed source categories. The U.S. Supreme Court ruled in *Massachusetts* v. *EPA* that GHGs [182] meet the definition of ''air pollutant'' in the CAA,[183] and subsequently premised its decision in *AEP* v. *Connecticut* [184]—that the CAA displaced any Federal common law right to compel reductions in CO_2 emissions from fossil fuel-fired power plants—on its view that CAA section 111 applies to GHG emissions. The D.C. Circuit confirmed in *American Lung Ass'n* v. *EPA,* 985 F.3d 914, 977 (D.C. Cir. 2021), discussed in section V.B.5, that the EPA is authorized to promulgate requirements under CAA section 111 for GHG from the fossil fuel-fired EGU source category notwithstanding that the source category is regulated under CAA section 112. As discussed in section V.B.6, the U.S. Supreme Court did not accept certiorari on the question whether the EPA could regulate GHGs from fossil-fuel fired EGUs under CAA section 111(d) when other pollutants from fossil-fuel fired EGUs are regulated under CAA section 112 in *West Virginia* v. *EPA,* 597 U.S. 697 (2022), and so the D.C. Circuit's holding on this issue remains good law.

In 2015, the EPA promulgated two rules that addressed CO_2 emissions from fossil fuel-fired EGUs. The first promulgated standards of performance for new fossil fuel-fired EGUs. ''Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule,'' (80 FR 64510; October 23, 2015) (2015 NSPS). The second promulgated emission guidelines for existing sources. ''Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule,'' (80 FR 64662; October 23, 2015) (Clean Power Plan, or CPP).

1. 2015 NSPS

In 2015, the EPA promulgated an NSPS to limit emissions of GHGs, manifested as CO_2, from newly constructed, modified, and reconstructed fossil fuel-fired electric utility steam generating units, *i.e.,* utility boilers and IGCC EGUs, and newly constructed and reconstructed stationary combustion turbine EGUs. These final standards are codified in 40 CFR part 60, subpart TTTT. In promulgating the NSPS for newly constructed fossil fuel-fired steam generating units, the EPA determined the BSER to be a new, highly efficient, supercritical pulverized coal (SCPC) EGU that implements post-combustion partial CCS technology. The EPA concluded that CCS was adequately demonstrated (including being technically feasible) and widely available and could be implemented at reasonable cost. The EPA identified natural gas co-firing and IGCC technology (either with natural gas co-firing or implementing partial CCS) as alternative methods of compliance.

The 2015 NSPS included standards of performance for steam generating units that undergo a ''reconstruction'' as well as units that implement ''large modifications,'' *(i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent). The 2015 NSPS did not establish standards of performance for steam generating units that undertake ''small modifications'' (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of less than or equal to 10 percent), due to the limited information available to inform the analysis of a BSER and corresponding standard of performance.

The 2015 NSPS also finalized standards of performance for newly constructed and reconstructed stationary combustion turbine EGUs. For newly constructed and reconstructed base load natural gas-fired stationary combustion turbines, the EPA finalized a standard based on efficient NGCC technology as the BSER. For newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines and for both base load and non-base load multi-fuel-fired stationary combustion turbines, the EPA finalized a heat input-based standard based on the use of lower-emitting fuels (referred to as clean fuels in the 2015 NSPS). The EPA did not promulgate final standards of performance for modified stationary combustion turbines due to lack of information. The 2015 NSPS remains in effect today.

The EPA received six petitions for reconsideration of the 2015 NSPS. On May 6, 2016 (81 FR 27442), the EPA denied five of the petitions on the basis that they did not satisfy the statutory conditions for reconsideration under CAA section 307(d)(7)(B) and deferred action on one petition that raised the issue of the treatment of biomass. Apart from these petitions, the EPA proposed to revise the 2015 NSPS in 2018, as discussed in section V.B.2.

Multiple parties also filed petitions for judicial review of the 2015 NSPS in the D.C. Circuit. These cases have been briefed and, on the EPA's motion, are being held in abeyance pending EPA action concerning the 2018 proposal to revise the 2015 NSPS.

In the 2015 NSPS, the EPA noted that it was authorized to regulate GHGs from the fossil fuel-fired EGU source categories because it had listed those source categories under CAA section 111(b)(1)(A). The EPA added that CAA section 111 did not require it to make a determination that GHGs from EGUs contribute significantly to dangerous air pollution (a pollutant-specific significant contribution finding), but in the alternative, the EPA did make that finding. It explained that ''[greenhouse gas] air pollution may reasonably be anticipated to endanger public health or welfare,'' 80 FR 64530 (October 23, 2015) and emphasized that power plants are ''by far the largest emitters'' of greenhouse gases among stationary sources in the U.S. *Id.* at 64522. In *American Lung Ass'n* v. *EPA,* 985 F.3d 977 (D.C. Cir. 2021), the court held that even if the EPA were required to determine that CO_2 from fossil fuel-fired EGUs contributes significantly to dangerous air pollution—and the court emphasized that it was not deciding that the EPA was required to make such a pollutant-specific determination—the determination in the alternative that the EPA made in the 2015 NSPS was not arbitrary and capricious and, accordingly, the EPA had a sufficient basis to regulate greenhouse gases from EGUs under CAA section 111(d) in the ACE Rule. This aspect of the decision remains good law. The EPA is not reopening and did not solicit comment on any of those determinations in the 2015 NSPS concerning its rational basis to regulate GHG emissions from EGUs or its alternative finding that GHG emissions from EGUs contribute significantly to dangerous air pollution.

2. 2018 NSPS Proposal To Revise the 2015 NSPS

In 2018, the EPA proposed to revise the NSPS for new, modified, and reconstructed fossil fuel-fired steam generating units and IGCC units, in the *Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Proposed Rule* (83 FR 65424;

[182] The EPA's 2009 endangerment finding defines the air pollution which may endanger public health and welfare as the well-mixed aggregate group of the following gases: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

[183] 549 U.S. 497, 520 (2007).

[184] 131 S. Ct. 2527, 2537–38 (2011).

December 20, 2018) (2018 NSPS Proposal). The EPA proposed to revise the NSPS for newly constructed units, based on a revised BSER of a highly efficient SCPC, without partial CCS. The EPA also proposed to revise the NSPS for modified and reconstructed units. As discussed in IX.A, in the present action, the EPA is withdrawing this proposed rule.[185]

3. Clean Power Plan

With the promulgation of the 2015 NSPS, the EPA also incurred a statutory obligation under CAA section 111(d) to issue emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs and stationary combustion turbine EGUs, which the EPA initially fulfilled with the promulgation of the CPP. See 80 FR 64662 (October 23, 2015). The EPA first determined that the BSER included three types of measures: (1) improving heat rate (*i.e.,* the amount of fuel that must be burned to generate a unit of electricity) at coal-fired steam plants; (2) substituting increased generation from lower-emitting NGCC plants for generation from higher-emitting steam plants (which are primarily coal-fired); and (3) substituting increased generation from new renewable energy sources for generation from fossil fuel-fired steam plants and combustion turbines. See 80 FR 64667 (October 23, 2015). The latter two measures are known as ''generation shifting'' because they involve shifting electricity generation from higher-emitting sources to lower-emitting ones. See 80 FR 64728–29 (October 23, 2015).

The EPA based this BSER determination on a technical record that evaluated generation shifting, including its cost-effectiveness, against the relevant statutory criteria for BSER and on a legal interpretation that the term ''system'' in CAA section 111(a)(1) is sufficiently broad to encompass shifting of generation from higher-emitting to lower-emitting sources. See 80 FR 64720 (October 23, 2015). The EPA then determined the ''degree of emission limitation achievable through the application of the [BSER],'' CAA section 111(a)(1), expressed as emission performance rates. See 80 FR 64667 (October 23, 2015). The EPA explained that a state would ''have to ensure, through its plan, that the emission standards it establishes for its sources individually, in the aggregate, or in combination with other measures undertaken by the state, represent the equivalent of'' those performance rates (80 FR 64667; October 23, 2015). Neither states nor sources were required to apply the specific measures identified in the BSER (80 FR 64667; October 23, 2015), and states could include trading or averaging programs in their state plans for compliance. See 80 FR 64840 (October 23, 2015).

Numerous states and private parties petitioned for review of the CPP before the D.C. Circuit. On February 9, 2016, the U.S. Supreme Court stayed the rule pending review, *West Virginia* v. *EPA,* 577 U.S. 1126 (2016). The D.C. Circuit held the litigation in abeyance, and ultimately dismissed it at the petitioners' request. *American Lung Ass'n,* 985 F.3d at 937.

4. The CPP Repeal and ACE Rule

In 2019, the EPA repealed the CPP and replaced it with the ACE Rule. In contrast to its interpretation of CAA section 111 in the CPP, in the ACE Rule the EPA determined that the statutory ''text and reasonable inferences from it'' make ''clear'' that a ''system'' of emission reduction under CAA section 111(a)(1) ''is limited to measures that can be applied to and at the level of the individual source,'' (84 FR 32529; July 8, 2019); that is, the system must be limited to control measures that could be applied at and to each source to reduce emissions at each source. See 84 FR 32523–24 (July 8, 2019). Specifically, the ACE Rule argued that the requirements in CAA sections 111(d)(1), (a)(3), and (a)(6), that each state establish a standard of performance ''for'' ''any existing source,'' defined, in general, as any ''building . . . [or] facility,'' and the requirement in CAA section 111(a)(1) that the degree of emission limitation must be ''achievable'' through the ''application'' of the BSER, by their terms, impose this limitation. The EPA concluded that generation shifting is not such a control measure. See 84 FR 32546 (July 8, 2019). Based on its view that the CPP was a ''major rule,'' the EPA further determined that, absent ''a clear statement from Congress,'' the term '' 'system of emission reduction' '' should not be read to encompass ''generation-shifting measures.'' See 84 FR 32529 (July 8, 2019). The EPA acknowledged, however, that ''[m]arket-based forces ha[d] already led to significant generation shifting in the power sector,'' (84 FR 32532; July 8, 2019), and that there was ''likely to be no difference between a world where the CPP is implemented and one where it is not.'' See 84 FR 32561 (July 8, 2019); the Regulatory Impact Analysis for the Repeal of the Clean Power Plan, and the Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, 2–1 to 2–5.[186]

In addition, the EPA promulgated in the ACE Rule a new set of emission guidelines for existing coal-fired steam-generating EGUs. See 84 FR 32532 (July 8, 2019). In light of ''the legal interpretation adopted in the repeal of the CPP,'' (84 FR 32532; July 8, 2019)—which ''limit[ed] 'standards of performance' to systems that can be applied at and to a stationary source,'' (84 FR 32534; July 8, 2019)—the EPA found the BSER to be heat rate improvements alone. See 84 FR 32535 (July 8, 2019). The EPA listed various technologies that could improve heat rate (84 FR 32536; July 8, 2019), and identified the ''degree of emission limitation achievable'' by ''providing ranges of expected [emission] reductions associated with each of the technologies.'' See 84 FR 32537–38 (July 8, 2019).

5. D.C. Circuit Decision in American Lung Association v. EPA Concerning the CPP Repeal and ACE Rule

Numerous states and private parties petitioned for review of the CPP Repeal and ACE Rule. In 2021, the D.C. Circuit vacated the ACE Rule, including the CPP Repeal. *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021). The court held, among other things, that CAA section 111(d) does not limit the EPA, in determining the BSER, to measures applied at and to an individual source. The court noted that ''the sole ground on which the EPA defends its abandonment of the [CPP] in favor of the ACE Rule is that the text of [CAA section 111] is clear and unambiguous in constraining the EPA to use only improvements at and to existing sources in its [BSER].'' 985 F.3d at 944. The court found ''nothing in the text, structure, history, or purpose of [CAA section 111] that compels the reading the EPA adopted.'' 985 F.3d at 957. The court likewise rejected the

[185] In the 2018 NSPS Proposal, the EPA solicited comment on whether it is required to make a determination that GHGs from a source category contribute significantly to dangerous air pollution as a predicate to promulgating a NSPS for GHG emissions from that source category for the first time. 83 FR 65432 (December 20, 2018). The EPA subsequently issued a final rule that provided that it would not regulate GHGs under CAA section 111 from a source category unless the GHGs from the category exceed 3 percent of total U.S. GHG emissions, on grounds that GHGs emitted in a lesser amount do not contribute significantly to dangerous air pollution. 86 FR 2652 (January 13, 2021). Shortly afterwards, the D.C. Circuit granted an unopposed motion by the EPA for voluntary vacatur and remand of the final rule. *California* v. *EPA,* No. 21–1035, doc. 1893155 (D.C. Cir. April 5, 2021).

[186] *https://www.epa.gov/sites/default/files/2019-06/documents/utilities_ria_final_cpp_repeal_and_ace_2019-06.pdf.*

view that the CPP's use of generation-shifting implicated a ''major question'' requiring unambiguous authorization by Congress. 985 F.3d at 958–68.

The D.C. Circuit concluded that, because the EPA had relied on an ''erroneous legal premise,'' both the CPP Repeal Rule and the ACE Rule should be vacated. 985 F.3d at 995. The court did not decide, however, ''whether the approach of the ACE Rule is a permissible reading of the statute as a matter of agency discretion,'' 985 F.3d at 944, and instead ''remanded to the EPA so that the Agency may 'consider the question afresh,' '' 985 F.3d at 995 (citations omitted).

The court also rejected the arguments that the EPA cannot regulate CO_2 emissions from coal-fired power plants under CAA section 111(d) at all because it had already regulated mercury emissions from coal-fired power plants under CAA section 112. 985 F.3d at 988. In addition, the court held that that the 2015 NSPS included a valid determination that greenhouse gases from the EGU source category contributed significantly to dangerous air pollution, which provided a sufficient basis for a CAA section 111(d) rule regulating greenhouse gases from existing fossil fuel-fired EGUs. *Id.* at 977.

Because the D.C. Circuit vacated the ACE Rule on the grounds noted above, it did not address the other challenges to the ACE Rule, including the arguments by Petitioners that the heat rate improvement BSER was inadequate because of the limited number of reductions it achieved and because the ACE Rule failed to include an appropriately specific degree of emission limitation.

Upon a motion from the EPA, the D.C. Circuit agreed to stay its mandate with respect to vacatur of the CPP Repeal, *American Lung Assn* v. *EPA,* No. 19–1140, Order (February 22, 2021), so that the CPP remained repealed. Therefore, following the D.C. Circuit's decision, no EPA rule under CAA section 111 to reduce GHGs from existing fossil fuel-fired EGUs remained in place.

6. U.S. Supreme Court Decision in West Virginia v. EPA Concerning the CPP

The Supreme Court granted petitions for certiorari from the D.C. Circuit's *American Lung Association* decision, limited to the question of whether CAA section 111 authorized the EPA to determine that ''generation shifting'' was the best system of emission reduction for fossil-fuel fired EGUs. The Supreme Court did not grant certiorari on the question of whether the EPA was authorized to regulate GHG emissions from fossil-fuel fired power plants under CAA section 111, when fossil-fuel fired power plants are regulated for other pollutants under CAA section 112. In 2022, the U.S. Supreme Court reversed the D.C. Circuit's vacatur of the ACE Rule's embedded repeal of the CPP. *West Virginia* v. *EPA,* 597 U.S. 697 (2022). The Supreme Court stated that CAA section 111 authorizes the EPA to determine the BSER and the degree of emission limitation that state plans must achieve. *Id.* at 2601–02. The Supreme Court concluded, however, that the CPP's BSER of ''generation-shifting'' raised a ''major question,'' and was not clearly authorized by section 111. The Court characterized the generation-shifting BSER as ''restructuring the Nation's overall mix of electricity generation,'' and stated that the EPA's claim that CAA section 111 authorized it to promulgate generation shifting as the BSER was ''not only unprecedented; it also effected a fundamental revision of the statute, changing it from one sort of scheme of regulation into an entirely different kind.'' *Id.* at 2612 (internal quotation marks, brackets, and citation omitted). The Court explained that the EPA, in prior rules under CAA section 111, had set emissions limits based on ''measures that would reduce pollution by causing the regulated source to operate more cleanly.'' *Id.* at 2610. The Court noted with approval those ''more traditional air pollution control measures,'' and gave as examples ''fuel-switching'' and ''add-on controls,'' which, the Court observed, the EPA had considered in the CPP. *Id.* at 2611 (internal quotations marks and citation omitted). In contrast, the Court continued, generation shifting was ''unprecedented'' because ''[r]ather than focus on improving the performance of individual sources, it would improve the overall power system by lowering the carbon intensity of power generation. And it would do that by forcing a shift throughout the power grid from one type of energy source to another.'' *Id.* at 2611–12 (internal quotation marks, emphasis, and citation omitted).

The Court recognized that a rule based on traditional measures ''may end up causing an incidental loss of coal's market share,'' but emphasized that the CPP was ''obvious[ly] differen[t]'' because, with its generation-shifting BSER, it ''simply announc[ed] what the market share of coal, natural gas, wind, and solar must be, and then require[ed] plants to reduce operations or subsidize their competitors to get there.'' *Id.* at 2613 n.4. The Court also emphasized ''the magnitude and consequence'' of the CPP. *Id.* at 2616. It noted ''the magnitude of this unprecedented power over American industry,'' *id.* at 2612 (internal quotation marks and citation omitted), and added that the EPA's adoption of generation shifting ''represent[ed] a transformative expansion in its regulatory authority.'' *Id.* at 2610 (internal quotation marks and citation omitted). The Court also viewed the CPP as promulgating ''a program that . . . Congress had considered and rejected multiple times.'' *Id.* at 2614 (internal quotation marks and citation omitted). For these and related reasons, the Court viewed the CPP as raising a major question, and therefore, requiring ''clear congressional authorization'' as a basis. *Id.* (internal quotation marks and citation omitted).

The Court declined to address the D.C. Circuit's conclusion that the text of CAA section 111 did not limit the type of ''system'' the EPA could consider as the BSER to measures applied at and to an individual source. *See id.* at 2615. Nor did the Court address the scope of the states' compliance flexibilities.

7. D.C. Circuit Order Reinstating the ACE Rule

On October 27, 2022, the D.C. Circuit responded to the U.S. Supreme Court's reversal by recalling its mandate for the vacatur of the ACE Rule. *American Lung Ass'n* v. *EPA,* No. 19–1140, Order (October 27, 2022). Accordingly, at that time, the ACE Rule came back into effect. The court also revised its judgment to deny petitions for review challenging the CPP Repeal Rule, consistent with the judgment in *West Virginia,* so that the CPP remains repealed. The court took further action denying several of the petitions for review unaffected by the Supreme Court's decision in *West Virginia,* which means that certain parts of its 2021 decision in *American Lung Association* remain in effect. These parts include the holding that the EPA's prior regulation of mercury emissions from coal-fired electric power plants under CAA section 112 does not preclude the Agency from regulating CO_2 from coal-fired electric power plants under CAA section 111, and the holding, discussed above, that the 2015 NSPS included a valid significant contribution determination and therefore provided a sufficient basis for a CAA section 111(d) rule regulating greenhouse gases from existing fossil fuel-fired EGUs. The court's holding to invalidate amendments to the implementing regulations applicable to emission guidelines under CAA section 111(d) that extended the preexisting schedules

for state and Federal actions and sources' compliance, also remains in force. Based on the EPA's stated intention to replace the ACE Rule, the court stayed further proceedings with respect to the ACE Rule, including the various challenges that its BSER was flawed because it did not achieve sufficient emission reductions and failed to specify an appropriately specific degree of emission limitation.

C. Detailed Discussion of CAA Section 111 Requirements

This section discusses in more detail the key requirements of CAA section 111 for both new and existing sources that are relevant for these rulemakings.

1. Approach to the Source Category and Subcategorizing

CAA section 111 requires the EPA first to list stationary source categories that cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare and then to regulate new sources within each such source category. CAA section 111(b)(2) grants the EPA discretion whether to ''distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards,'' which we refer to as ''subcategorizing.'' Whether and how to subcategorize is a decision for which the EPA is entitled to a ''high degree of deference'' because it entails ''scientific judgment.'' *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

Although CAA section 111(d)(1) does not explicitly address subcategorization, since its first regulations implementing the CAA, the EPA has interpreted it to authorize the Agency to exercise discretion as to whether and, if so, how to subcategorize, for the following reasons. CAA section 111(d)(1) grants the EPA authority to ''prescribe regulations which shall establish a procedure . . . under which each State shall submit to the Administrator a plan [with standards of performance for existing sources.]'' The EPA promulgates emission guidelines under this provision directing the states to regulate existing sources. The Supreme Court has recognized that, under CAA section 111(d), the ''Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, 'the best system of emission reduction . . . that has been adequately demonstrated for [existing covered] facilities.' *West Virginia,* 597 U.S. at 710 (citations omitted).

The EPA's authority to determine the BSER includes the authority to create subcategories that tailor the BSER for differently situated sets of sources. Again, for new sources, CAA section 111(b)(2) confers authority for the EPA to ''distinguish among classes, types, and sizes within categories.'' Though CAA section 111(d) does not speak specifically to the creation of subcategories for a category of existing sources, the authority to identify the ''best'' system of emission reduction for existing sources includes the discretion to differentiate between differently situated sources in the category, and group those sources into subcategories in appropriate circumstances. The size, type, class, and other characteristics can make different emission controls more appropriate for different sources. A system of emission reduction that is ''best'' for some sources may not be ''best'' for others with different characteristics. For more than four decades, the EPA has interpreted CAA section 111(d) to confer authority on the Agency to create subcategories. The EPA's implementing regulations under CAA section 111(d), promulgated in 1975, 40 FR 53340 (November 17, 1975), provide that the Administrator will specify different emission guidelines or compliance times or both ''for different sizes, types, and classes of designated facilities when [based on] costs of control, physical limitations, geographical location, or [based on] similar factors.'' [187] This regulation governs the EPA's general authority to subcategorize under CAA section 111(d), and the EPA is not reopening that issue here. At the time of promulgation, the EPA explained that subcategorization allows the EPA to take into account ''differences in sizes and types of facilities and similar considerations, including differences in control costs that may be involved for sources located in different parts of the country'' so that the ''EPA's emission guidelines will in effect be tailored to what is reasonably achievable by particular classes of existing sources. . . .'' *Id.* at 53343. The EPA's authority to ''distinguish among classes, types, and sizes within categories,'' as provided under CAA section 111(b)(2), generally allows the Agency to place types of sources into subcategories. This is consistent with the commonly understood meaning of the term ''type'' in CAA section 111(b)(2): ''a particular kind, class, or group,'' or ''qualities common to a number of individuals that distinguish them as an identifiable class.'' See *https://www.merriam-webster.com/dictionary/type*.

The EPA has developed subcategories in many rulemakings under CAA section 111 since the 1970s. These rulemakings have included subcategories on the basis of the size of the sources, see 40 CFR 60.40b(b)(1)–(2) (subcategorizing certain coal-fired steam generating units on the basis of heat input capacity); the types of fuel combusted, *see Sierra Club,* v. *EPA,* 657 F.2d 298, 318–19 (D.C. Cir. 1981) (upholding a rulemaking that established different NSPS ''for utility plants that burn coal of varying sulfur content''), 2015 NSPS, 80 FR 64510, 64602 (table 15) (October 23, 2015) (subdividing new combustion turbines on the basis of type of fuel combusted); the types of equipment used to produce products, see 81 FR 35824 (June 3, 2016) (promulgating separate NSPS for many types of oil and gas sources, such as centrifugal compressors, pneumatic controllers, and well sites); types of manufacturing processes used to produce product, see 42 FR 12022 (March 1, 1977) (announcing availability of final guideline document for control of atmospheric fluoride emissions from existing phosphate fertilizer plants) and ''Final Guideline Document: Control of Fluoride Emissions From Existing Phosphate Fertilizer Plants,'' EPA–450/2–77–005 1–7 to 1–9, including table 1–2 (applying different control requirements for different manufacturing operations for phosphate fertilizer); levels of utilization of the sources, see 2015 NSPS, 80 FR 64510, 64602 (table 15) (October 23, 2015) (dividing new natural gas-fired combustion turbines into the subcategories of base load and non-base load); the activity level of the sources, see 81 FR 59276, 59278–79 (August 29, 2016) (dividing municipal solid waste landfills into the subcategories of active and closed landfills); and geographic location of the sources, see 71 FR 38482 (July 6, 2006) (SO_2 NSPS for stationary combustion turbines subcategorizing turbines on the basis of whether they are located in, for example, a continental area, a non-continental area, the part of Alaska north of the Arctic Circle, and the rest of Alaska). Thus, the EPA has subcategorized many times in rulemaking under CAA sections 111(b) and 111(d) and based on a wide variety of physical, locational, and operational characteristics.

Regardless of whether the EPA subcategorizes within a source category

[187] 40 CFR 60.22(b)(5), 60.22a(b)(5). Because the definition of subcategories depends on characteristics relevant to the BSER, and because those characteristics can differ as between new and existing sources, the EPA may establish different subcategories as between new and existing sources.

for purposes of determining the BSER and the degree of emission limitation achievable, a state retains certain flexibility in assigning standards of performance to its affected EGUs. The statutory framework for CAA section 111(d) emission guidelines, and the flexibilities available to states within that framework, are discussed below.

2. Key Elements of Determining a Standard of Performance

Congress first included the definition of ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA to largely restore the definition as it read in the 1970 CAAA. The current text of CAA section 111(a)(1) reads: ''The term 'standard of performance' means a standard for emission of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' The D.C. Circuit has reviewed CAA section 111 rulemakings on numerous occasions since 1973,[188] and has developed a body of caselaw that interprets the term ''standard of performance,'' as discussed throughout this preamble.

The basis for standards of performance, whether promulgated by the EPA under CAA section 111(b) or established by the states under CAA section 111(d), is that the EPA determines the ''degree of emission limitation'' that is ''achievable'' by the sources by application of a ''system of emission reduction'' that the EPA determines is ''adequately demonstrated,'' ''taking into account'' the factors of ''cost . . . and any nonair quality health and environmental impact and energy requirements,'' and that the EPA determines to be the ''best.'' The D.C. Circuit has stated that in determining the ''best'' system, the EPA must also take into account ''the amount of air pollution'' [189] reduced and the role of ''technological innovation.'' [190] The D.C. Circuit has also stated that to determine the ''best'' system, the EPA may weigh the various factors identified in the statute and caselaw against each other, and has emphasized that the EPA has discretion in weighing the factors.[191] [192]

The EPA's overall approach to determining the BSER and degree of emission limitation achievable, which incorporates the various elements, is as follows: The EPA identifies ''system[s] of emission reduction'' that have been ''adequately demonstrated'' for a particular source category and determines the ''best'' of these systems after evaluating the amount of emission reductions, costs, any non-air health and environmental impacts, and energy requirements. As discussed below, for each of numerous subcategories, the EPA followed this approach to determine the BSER on the basis that the identified costs are reasonable and that the BSER is rational in light of the statutory factors, including the amount of emission reductions, that the EPA examined in its BSER analysis, consistent with governing precedent.

After determining the BSER, the EPA determines an achievable emission limit based on application of the BSER.[193] For a CAA section 111(b) rule, the EPA determines the standard of performance that reflects the achievable emission limit. For a CAA section 111(d) rule, the states have the obligation of establishing standards of performance for the affected sources that reflect the degree of emission limitation that the EPA has determined. As discussed below, the EPA is finalizing these determinations in association with each of the BSER determinations.

The remainder of this subsection discusses each element in our general analytical approach.

a. System of Emission Reduction

The CAA does not define the phrase ''system of emission reduction.'' In *West Virginia* v. *EPA,* the Supreme Court recognized that historically, the EPA had looked to ''measures that improve the pollution performance of individual sources and followed a ''technology-based approach'' in identifying systems of emission reduction. In particular, the Court identified ''the sort of 'systems of emission reduction' [the EPA] had always before selected,'' which included '' 'efficiency improvements, fuel-switching,' and 'add-on controls'.'' 597 U.S. at 727 (quoting the Clean Power Plan).[194] Section 111 itself recognizes that such systems may include off-site activities that may reduce a source's pollution contribution, identifying ''precombustion cleaning or treatment of fuels'' as a ''system'' of ''emission reduction.'' 42 U.S.C. 7411(a)(7)(B). A ''system of emission reduction'' thus, at a minimum, includes measures that an individual source applies that improve the emissions performance of that source. Measures are fairly characterized as improving the pollution performance of a source where they reduce the individual source's overall contribution to pollution.

In *West Virginia,* the Supreme Court did not define the term ''system of emissions reduction,'' and so did not rule on whether ''system of emission reduction'' is limited to those measures that the EPA has historically relied upon. It did go on to apply the major questions doctrine to hold that the term ''system'' does not provide the requisite clear authorization to support the Clean Power Plan's BSER, which the Court described as ''carbon emissions caps based on a generation shifting approach.'' *Id.* at 2614. While the Court did not define the outer bounds of the meaning of ''system,'' systems of emissions reduction like fuel switching, add-on controls, and efficiency improvements fall comfortably within the scope of prior practice as recognized by the Supreme Court.

b. ''Adequately Demonstrated''

Under CAA section 111(a)(1), an essential, although not sufficient, condition for a ''system of emission

[188] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011); *American Lung Ass'n* v. *EPA,* 985 F.3d 914 (D.C. Cir. 2021), *rev'd in part, West Virginia* v. *EPA,* 597 U.S. 697 (2022). *See also Delaware* v. *EPA,* No. 13–1093 (D.C. Cir. May 1, 2015).

[189] *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

[190] *See Sierra Club* v. *Costle,* 657 F.2d at 347.

[191] *See Lignite Energy Council,* 198 F.3d at 933.

[192] CAA section 111(a)(1), by its terms states that the factors enumerated in the parenthetical are part of the ''adequately demonstrated'' determination. In addition, the D.C. Circuit's caselaw makes clear that the EPA may consider these same factors when it determines which adequately demonstrated system of emission reduction is the ''best.'' *See Sierra Club* v. *Costle,* 657 F.2d at 330 (recognizing that CAA section 111 gives the EPA authority ''when determining the best technological system to weigh cost, energy, and environmental impacts'').

[193] See, *e.g.,* Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air pollutants Reviews (77 FR 49494; August 16, 2012) (describing the three-step analysis in setting a standard of performance).

[194] As noted in section V.B.4 of this preamble, the ACE Rule adopted the interpretation that CAA section 111(a)(1), by its plain language, limits ''system of emission reduction'' to those control measures that could be applied at and to each source to reduce emissions at each source. 84 FR 32523–24 (July 8, 2019). The EPA has subsequently rejected that interpretation as too narrow. *See Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d),* 88 FR 80535 (November 17, 2023).

reduction'' to serve as the basis for an ''achievable'' emission standard is that the Administrator must determine that the system is ''adequately demonstrated.'' The concepts of adequate demonstration and achievability are closely related: as the D.C. Circuit has stated, ''[i]t is the system which must be adequately demonstrated and the standard which must be achievable,'' [195] through application of the system. An achievable standard means a standard based on the EPA's record-based finding that sufficient evidence exists to reasonably determine that the affected sources in the source category can adopt a specific system of emission reduction to achieve the specified degree of emission limitation. As discussed below, consistent with Congress's use of the word ''demonstrated,'' the caselaw has approved the EPA's ''adequately demonstrated'' determinations concerning systems utilized at test sources or other individual sources operating at commercial scale. The case law also authorizes the EPA to set an emissions standard at levels more stringent than has regularly been achieved, based on the understanding that sources will be able to adopt specific technological improvements to the system in question that will enable them to achieve the lower standard. Importantly, and contrary to some comments received on the proposed rule, CAA section 111(a)(1) does *not* require that a system of emission reduction exist in widespread commercial use in order to satisfy the ''adequately demonstrated'' requirement.[196] Instead, CAA section 111(a)(1) authorizes the EPA to establish standards which encourage the deployment of more effective systems of emission reduction that have been adequately demonstrated but that are not yet in widespread use. This aligns with Congress's purpose in enacting the CAA, in particular its recognition that polluting sources were not widely adopting emission control technology on a voluntary basis and that Federal regulation was necessary to spur the development and deployment of those technologies.[197]

[195] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (1973) (emphasis omitted).

[196] *See, e.g., Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973) (in which the D.C. Circuit upheld a CAA section 111 standard based on a system which had been extensively used in Europe but at the time of promulgation was only in use in the United States at one plant).

[197] In introducing the respective bills which ultimately became the 1970 Clean Air Act upon Conference Committee review, both the House and Senate emphasized the urgency of the matter at hand, the intended power of the new legislation, and in particular its technology-forcing nature. The first page of the House report declared that ''[t]he purpose of the legislation reported unanimously by [Committee was] to speed up, expand, and intensify the war against air pollution in the United States . . .'' H.R. Rep. No. 17255 at 1 (1970). It was clear, stated the House report, that until that point ''the strategies which [the United States had] pursued in the war against air pollution [had] been inadequate in several important respects, and the methods employed in implementing those strategies often [had] been slow and less effective than they might have been.'' *Id.* The Senate report agreed, stating that their bill would ''provide a much more intensive and comprehensive attack on air pollution,'' 1 S. 4358 at 4 (1970), including, crucially, by increased federal involvement. *See id.*

[198] The D.C. Circuit stated in *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 786 (D.C. Cir. 1976) ''The standard of review of actions of the Administrator in setting standards of performance is an appropriately deferential one, and we are to affirm the action of the Administrator unless it is ''arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law,'' 5 U.S.C. 706(2)(A) (1970). Since this is one of those ''highly technical areas, where our understanding of the import of the evidence is attenuated, our readiness to review evidentiary support for decisions must be correspondingly restrained.'' *Ethyl Corporation* v. *EPA,* 96 S. Ct. 2663 (1976). ''Our 'expertise' is not in setting standards for emission control, but in determining if the standards as set are the result of reasoned decision-making.'' *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 434 (D.C. Cir. 1973)) (cleaned up).''

[199] 42 U.S.C. 7409(b)(1).

[200] 744 F.3d 1334 (D.C. Cir. 2013).

[201] *Id.*

[202] While not relevant here, because CCS is already in existence, the text, case law, and legislative history make a compelling case that EPA is authorized to go farther than this, and may make a projection regarding the way in which a particular system will develop to allow for greater emissions reductions in the future. *See* 80 FR 64556–58 (discussion of ''adequately demonstrated'' in 2015 NSPS).

[203] Webster's New World Dictionary: Second College Edition (David B. Guralnik, ed., 1972).

i. Plain Text, Statutory Context, and Legislative History of the ''Adequately Demonstrated'' Provision in CAA Section 111(a)(1)

Analysis of the plain text, statutory context, and legislative history of CAA section 111(a)(1) establishes two primary themes. First, Congress assigned the task of determining the appropriate BSER to the Administrator, based on a reasonable review of available evidence. Second, Congress authorized the EPA to set a standard, based on the evidence, that encourages broader adoption of an emissions-reducing technological approach that may not yet be in widespread use.

The plain text of CAA section 111(a)(1), and in particular the phrase ''the Administrator determines'' and the term ''adequately,'' confer discretion to the EPA in identifying the appropriate system. Rather than providing specific criteria for determining what constitutes appropriate evidence, Congress directed the Administrator to ''determine[ ]'' that the demonstration is ''adequate[ ].'' Courts have typically deferred to the EPA's scientific and technological judgments in making such determinations.[198] Further, use of the term ''adequate'' in provisions throughout the CAA highlights EPA flexibility and discretion in setting standards and in analyzing data that forms the basis for standard setting.

In setting NAAQS under CAA section 109, for example, the EPA is directed to determine, according to ''the judgment of the Administrator,'' an ''adequate margin of safety.'' [199] The D.C. Circuit has held that the use of the term ''adequate'' confers significant deference to the Administrator's scientific and technological judgment. In *Mississippi* v. *EPA,*[200] for example, the D.C. Circuit in 2013 upheld the EPA's choice to set the NAAQS for ozone below 0.08 ppm, and noted that any disagreements with the EPA's interpretations of the scientific evidence that underlay this decision ''must come from those who are qualified to evaluate the science, not [the court].'' [201] This *Mississippi* v. *EPA* precedent aligns with the general standard for judicial review of the EPA's understanding of the evidence under CAA section 307(d)(9)(A) (''arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law'').

The plain language of the phrase ''has been adequately demonstrated,'' in context, and in light of the legislative history, further strongly indicates that the system in question need not be in widespread use at the time the EPA's rule is published. To the contrary, CAA section 111(a)(1) authorizes technology forcing, in the sense that the EPA is authorized to promote a system which is not yet in widespread use; provided the technology is in existence and the EPA has adequate evidence to extrapolate.[202]

Some commenters argued that use of the phrase ''has been'' in ''has been adequately demonstrated'' means that the system must be in widespread commercial use at the time of rule promulgation. We disagree. Considering the plain text, the use of the past tense, ''*has been* adequately demonstrated'' indicates a requirement that the technology *currently* be demonstrated. However, ''demonstrated'' in common usage at the time of enactment meant to ''explain or make clear by using examples, experiments, *etc.*'' [203] As a general matter, and as this definition indicates, the term ''to demonstrate'' suggests the need for a test or study—as in, for example, a ''demonstration

project'' or ''demonstration plant''—that is, examples of technological feasibility.

The statutory context is also useful in establishing that where Congress wanted to specify the availability of the control system, it did so. The only other use of the exact term ''adequately demonstrated'' occurs in CAA section 119, which establishes that, in order for the EPA to require a particular ''means of emission limitation'' for smelters, the Agency must establish that such means ''has been adequately demonstrated to be reasonably available. . . .'' [204] The lack of the phrase ''reasonably available'' in CAA section 111(a)(1) is notable, and suggests that a system may be ''adequately demonstrated'' under CAA section 111 even if it is not ''reasonably available'' for every single source.[205]

The term ''demonstration'' also appears in CAA section 103 in an instructive context. CAA section 103, which establishes a ''national research and development program for the prevention and control of air pollution'' directs that as part of this program, the EPA shall ''conduct, and promote the coordination and acceleration of, research, investigations, experiments, demonstrations, surveys, and studies relating to'' the issue of air pollution.[206] According to the canon of *noscitur a sociis,* associated words in a list bear on one another's meaning.[207] In CAA section 103, the word ''demonstrations'' appears alongside ''research,'' ''investigations,'' ''experiments,'' and ''studies''—all words suggesting the development of new and emerging technology. This supports interpreting CAA section 111(a)(1) to authorize the EPA to determine a system of emission reduction to be ''adequately demonstrated'' based on demonstration projects, testing, examples, or comparable evidence.

Finally, the legislative history of the CAA in general, and section 111 in particular, strongly supports the point that BSER technology need not be in widespread use at the time of rule enactment. The final language of CAA section 111(a)(1), requiring that systems of emission reduction be ''adequately demonstrated,'' was the result of compromise in the Conference Committee between the House and Senate bill language. The House bill would have required that the EPA give ''appropriate consideration to technological and economic feasibility'' when establishing standards.[208] The Senate bill would have required that standards ''reflect the greatest degree of emission control which the Secretary determines to be achievable through application of the latest available control technology, processes, operating methods, or other alternatives.'' [209] Although the exact language of neither the House nor Senate bill was adopted in the final bill, both reports made clear their intent that CAA section 111 would be significantly technology-forcing. In particular, the Senate Report referred to ''available control technology''—a phrase that, as just noted, the Senate bill included—but clarified that the technology need not ''be in actual, routine use somewhere.'' [210] The House Report explained that EPA regulations would ''prevent and control such emissions to the fullest extent compatible with the available technology and economic feasibility as determined by [the EPA],'' and ''[i]n order to be considered 'available' the technology may not be one which constitutes a purely theoretical or experimental means of preventing or controlling air pollution.'' [211] This last statement implies that the House Report anticipated that the EPA's determination may be technology forcing. Nothing in the legislative history suggests that Congress intended that the technology already be in widespread commercial use.

ii. Caselaw

In a series of cases reviewing standards for new sources, the D.C. Circuit has held that an adequately demonstrated standard of performance may reflect the EPA's reasonable projection of what that particular system may be expected to achieve going forward, extrapolating from available data from pilot projects or individual commercial-scale sources. A standard may be considered achievable even if the system upon which the standard is based has not regularly achieved the standard in testing. See, *e.g., Essex Chem. Corp.* v. *Ruckelshaus* [212] (upholding a standard of 4.0 lbs per ton based on a system whose average control rate was 4.6 lbs per ton, and which had achieved 4.0 lbs per ton on only three occasions and '''nearly equaled' [the standard] on the average of nineteen different readings.'') [213] The *Ruckelshaus* court concluded that the EPA's extrapolation from available data was ''the result of the exercise of reasoned discretion by the Administrator'' and therefore ''[could not] be upset by [the] court.'' [214] The court also emphasized that in order to be considered achievable, the standard set by the EPA need not be regularly or even specifically achieved at the time of rule promulgation. Instead, according to the court, ''[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.'' [215]

Case law also establishes that the EPA may set a standard more stringent than has regularly been achieved based on its identification of specific available technological improvements to the system. See *Sierra Club* v. *Costle* [216] (upholding a 90 percent standard for SO_2 emissions from coal-fired steam generators despite the fact that not all plants had previously achieved this standard, based on the EPA's expectations for improved performance with specific technological fixes and the use of ''coal washing'' going forward).[217] Further, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different,

[204] The statutory text at CAA section 119 continues, ''as determined by the Administrator, taking into account the cost of compliance, nonair quality health and environmental impact, and energy consideration.'' 42 U.S.C. 7419(b)(3).

[205] It should also be noted that the section 119 language was added as part of the 1977 Clean Air Act amendments, while the section 111 language was established in 1970. Thus, Congress was aware of section 111's more permissive language when it added the ''reasonably available'' language to section 119.

[206] 42 U.S.C. 7403(a)(1).

[207] As the Supreme Court recently explained in *Dubin* v. *United States,* even words that might be indeterminate alone may be more easily interpreted in ''company,'' because per *noscitur a sociis* ''a word is known by the company it keeps.'' 599 U.S. 110, 244 (2023).

[208] H.R. Rep. No. 17255 at 921 (1970) (quoting CAA Sec. 112(a), as proposed).

[209] S. Rept. 4358 at 91 (quoting CAA Sec. 113(b)(2), as proposed).

[210] S. Rep. 4358 at 15–16 (1970). The Senate Report went on to say that the EPA should ''examine the degree of emission control that has been or can be achieved through the application of technology which is available or normally can be made available . . . at a cost and at a time which [the Agency] determines to be reasonable.'' *Id.* Again, this language rebuts any suggestion that a BSER technology must be in widespread use at the time of rule enactment—Congress assumed only that the technology would be ''available'' or even that it ''[could] be made available,'' not that it would be *already* broadly used.

[211] H.R. Rep. No. 17255 at 900.

[212] 486 F.2d 427 (D.C. Cir. 1973).

[213] *Id.* at 437.

[214] *Id.* at 437.

[215] *Id.* at 433–34 (D.C. Cir. 1973). *See also Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), which supports the point that EPA may extrapolate from testing results, rather than relying on consistent performance, to identify an appropriate system and standard based on that system. In that case, EPA analyzed scrubber performance by considering performance during short-term testing periods. *See id.* at 377.

[216] 657 F.2d 298 (D.C. Cir. 1981).

[217] *Id.* at 365, 370–73; 365.

related, source. See *Lignite Energy Council* v. *EPA* [218] (holding it permissible to base a standard for industrial boilers on application of SCR based on extrapolated information about the application of SCR on utility boilers).[219] The *Lignite* court clarified that ''where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture,'' but the ''EPA may compensate for a *shortage* of data through the use of other qualitative methods, including the reasonable extrapolation of a technology's performance in other industries.'' [220]

As a general matter, the case law is clear that at the time of Rule promulgation, the system which the EPA establishes as BSER need not be in widespread use. See, *e.g., Ruckelshaus* [221] (upholding a standard based on a relatively new system which was in use at only one United States plant at the time of rule promulgation. Although the system was in use more extensively in Europe at the time of rule promulgation, the EPA based its analysis on test results from the lone U.S. plant only.) [222] This makes good sense, because, as discussed above, CAA section 111(a)(1) authorizes a technology-forcing standard that encourages broader adoption of an emissions-reducing technological approach that is not yet broadly used. It follows that at the time of promulgation, not every source will be prepared to adopt the BSER at once. Instead, as discussed next, the EPA's responsibility is to determine that the technology can be adopted in a reasonable period of time, and to base its requirements on this understanding.

iii. Compliance Timeframe

The preceding subsections have shown various circumstances under which the EPA may determine that a system of emission reduction is ''adequately demonstrated.'' In order to establish that a system is appropriate for the source category as a whole, the EPA must also demonstrate that the industry can deploy the technology at scale in the compliance timeframe. The D.C. Circuit has stated that the EPA may determine a ''system of emission reduction'' to be ''adequately demonstrated'' if the EPA reasonably projects that it may be more broadly deployed with adequate lead time. This view is well-grounded in the purposes of CAA section 111(a)(1), discussed above, which aim to control dangerous air pollution by allowing for standards which encourage more widespread adoption of a technology demonstrated at individual plants.

As a practical matter, CAA section 111's allowance for lead time recognizes that existing pollution control systems may be complex and may require a predictable amount of time for sources across the source category to be able to design, acquire, install, test, and begin to operate them.[223] Time may also be required to allow for the development of skilled labor, and materials like steel, concrete, and speciality parts. Accordingly, in setting 111 standards for both new and existing sources, the EPA has typically allowed for some amount of time before sources must demonstrate compliance with the standards. For instance, in the 2015 NSPS for residential wood heaters, the EPA established a ''stepped compliance approach'' which phased in requirements over 5 years to ''allow manufacturers lead time to develop, test, field evaluate and certify current technologies'' across their model lines.[224] The EPA also allowed for a series of phase-ins of various requirements in the 2023 oil and gas NSPS.[225] For example: the EPA finalized a compliance deadline for process controllers allowing for 1 year from the effective date of the final rule, to allow for delays in equipment availability; [226] the EPA established a 1-year lead time period for pumps, also in response to possible equipment and labor shortages; [227] and the EPA built in 24 months between publication in the **Federal Register** and the commencement of a requirement to end routine flaring and route associated gas to a sales line.[228]

Finally, the EPA's longstanding regulations for new source performance standards under CAA section 111 specifically authorize a minimum period for lead time. Pursuant to 40 CFR 60.11, compliance with CAA section 111 standards is generally determined in accordance with performance tests conducted under 40 CFR 60.8. Both of these regulatory provisions were adopted in 1971. Under 40 CFR 60.8, source performance is generally measured via performance tests, which must typically be carried out ''within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act. . . .'' [229] The fact that this provision has been in place for over 50 years indicates that the EPA has long recognized the need for lead time for at least one component of control development.[230]

c. Costs

Under CAA section 111(a)(1), in determining whether a particular emission control is the ''best system of emission reduction . . . adequately demonstrated,'' the EPA is required to take into account ''the cost of achieving [the emission] reduction.'' Although the CAA does not describe how the EPA is to account for costs to affected sources, the D.C. Circuit has formulated the cost standard in various ways, including stating that the EPA may not adopt a standard the cost of which would be ''excessive'' or ''unreasonable.'' [231] [232]

[218] 198 F.3d 930 (D.C. Cir. 1999).

[219] *See id.* at 933–34.

[220] *Id.* at 934 (emphasis added).

[221] 486 F.2d 375 (D.C. Cir. 1973). *See also Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), which supports the point that EPA may extrapolate from testing results, rather than relying on consistent performance, to identify an appropriate system and standard based on that system. In that case, EPA analyzed scrubber performance by considering performance during short-term testing periods. *See id.* at 377.

[222] 486 F.2d at 435–36.

[223] As discussed above, although the EPA is not relying on this point for purposes of these rules, it should be noted that the EPA may determine a system of emission reduction to be adequately demonstrated based on some amount of projection, even if some aspects of the system are still in development. Thus, the authorization for lead time accommodates the development of projected technology.

[224] *See* Standards of Performance for New Residential Wood Heaters, New Residential Hydronic Heaters and Forced-Air Furnaces, 80 FR 13672, 13676 (March 16, 2015).

[225] *See* Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review. 89 FR 16943 (March 8, 2024).

[226] *See id.* at 16929.

[227] *See id.* at 16937.

[228] *See id.* at 16886.

[229] 40 CFR 60.8.

[230] For further discussion of lead time in the context of this rulemaking, see section VIII.F.

[231] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981). *See* 79 FR 1430, 1464 (January 8, 2014); *Lignite Energy Council,* 198 F.3d at 933 (costs may not be ''exorbitant''); *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975) (costs may not be ''greater than the industry could bear and survive'').

[232] These cost formulations are consistent with the legislative history of CAA section 111. The 1977 House Committee Report noted:

In the [1970] Congress [sic: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.

1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

The implicit consideration of economic factors in determining whether technology is ''available'' should not affect the usefulness of this section. The overriding purpose of this section would be to

The EPA has discretion in its consideration of cost under section 111(a), both in determining the appropriate level of costs and in balancing costs with other BSER factors.[233] To determine the BSER, the EPA must weigh the relevant factors, including the cost of controls and the amount of emission reductions, as well as other factors.[234]

The D.C. Circuit has repeatedly upheld the EPA's consideration of cost in reviewing standards of performance. In several cases, the court upheld standards that entailed significant costs, consistent with Congress's view that ''the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.'' [235] *See Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 440 (D.C. Cir. 1973); [236] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 387–88 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding NSPS imposing controls on SO_2 emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial. The EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.'').

In its CAA section 111 rulemakings, the EPA has frequently used a cost-effectiveness metric, which determines the cost in dollars for each ton or other quantity of the regulated air pollutant removed through the system of emission reduction. *See, e.g.,* 81 FR 35824 (June 3, 2016) (NSPS for GHG and VOC emissions for the oil and natural gas source category); 71 FR 9866, 9870 (February 27, 2006) (NSPS for NO_X, SO_2, and PM emissions from fossil fuel-fired electric utility steam generating units); 61 FR 9905, 9910 (March 12, 1996) (NSPS and emission guidelines for nonmethane organic compounds and landfill gas from new and existing municipal solid waste landfills); 50 FR 40158 (October 1, 1985) (NSPS for SO_2 emissions from sweetening and sulfur recovery units in natural gas processing plants). This metric allows the EPA to compare the amount a regulation would require sources to pay to reduce a particular pollutant across regulations and industries. In rules for the electric power sector, the EPA has also looked at a metric that determines the dollar increase in the cost of a MWh of electricity generated by the affected sources due to the emission controls, which shows the cost of controls relative to the output of electricity. *See* section VII.C.1.a.ii of this preamble, which discusses $/MWh costs of the Good Neighbor Plan for the 2015 Ozone NAAQS (88 FR 36654; June 5, 2023) and the Cross-State Air Pollution Rule (CSAPR) (76 FR 48208; August 8, 2011). This metric facilitates comparing costs across regulations and pollutants. In these final actions, as explained herein, the EPA looks at both of these metrics, in addition to other cost evaluations, to assess the cost reasonableness of the final requirements. The EPA's consideration of cost reasonableness in this way meets the statutory requirement that the EPA take into account ''the cost of achieving [the emission] reduction'' under section 111(a)(1).

d. Non-Air Quality Health and Environmental Impact and Energy Requirements

Under CAA section 111(a)(1), the EPA is required to take into account ''any nonair quality health and environmental impact and energy requirements'' in determining the BSER. Non-air quality health and environmental impacts may include the impacts of the disposal of byproducts of the air pollution controls, or requirements of the air pollution control equipment for water. *Portland Cement Ass'n* v. *Ruckelshaus,* 465 F.2d 375, 387–88 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974). Energy requirements may include the impact, if any, of the air pollution controls on the source's own energy needs.

e. Sector or Nationwide Component of Factors in Determining the BSER

Another component of the D.C. Circuit's interpretations of CAA section 111 is that the EPA may consider the various factors it is required to consider on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[237] The D.C. Circuit based this interpretation—which it made in the 1981 *Sierra Club* v. *Costle* case regarding the NSPS for new power plants—on a review of the legislative history, stating,

> [T]he Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[238]

The court has upheld EPA rules that the EPA ''justified . . . in terms of the policies of the Act,'' including balancing long-term national and regional impacts. For example, the court upheld a standard of performance for SO_2 emissions from new coal-fired power plants on grounds that it—

> reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. . . .[239]

The EPA interprets this caselaw to authorize it to assess the impacts of the controls it is considering as the BSER, including their costs and implications for the energy system, on a sector-wide, regional, or national basis, as appropriate. For example, the EPA may assess whether controls it is considering would create risks to the reliability of the electricity system in a particular area or nationwide and, if they would, to reject those controls as the BSER.

f. ''Best''

In determining which adequately demonstrated system of emission reduction is the ''best,'' the EPA has broad discretion. In *AEP* v. *Connecticut,* 564 U.S. 410, 427 (2011), the Supreme Court explained that under CAA section 111, ''[t]he appropriate amount of regulation in any particular greenhouse gas-producing sector cannot be prescribed in a vacuum: . . . informed assessment of competing interests is required. Along with the environmental benefit potentially achievable, our Nation's energy needs and the possibility of economic disruption must weigh in the balance. The Clean Air Act entrusts such complex balancing to the EPA in the first instance, in combination with state regulators. Each ''standard of performance'' the EPA sets must ''tak[e] into account the cost of achieving [emissions] reduction and any nonair quality health and environmental impact and energy requirements.'' (paragraphing revised; citations omitted)).

prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91–1196 at 16.

[233] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[234] *Id.* (EPA's conclusion that the high cost of control was acceptable was ''a judgment call with which we are not inclined to quarrel'').

[235] 1977 House Committee Report at 184.

[236] The costs for these standards were described in the rulemakings. See 36 FR 24876 (December 23, 1971), 37 FR 5769 (March 21, 1972).

[237] See 79 FR 1430, 1465 (January 8, 2014) (citing *Sierra Club* v. *Costle,* 657 F.2d at 351).

[238] *Sierra Club* v. *Costle,* 657 F.2d at 331 (citations omitted) (citing legislative history).

[239] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583–84; June 11, 1979).

Likewise, in *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,'' [240] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard,'' including the amount of emission reductions, the cost of the controls, and the non-air quality environmental impacts and energy requirements.[241] And in *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them . . . . EPA's choice [of the 'best system'] will be sustained unless the environmental or economic costs of using the technology are exorbitant . . . . EPA [has] considerable discretion under section 111.[242]

Importantly, the courts recognize that the EPA must consider several factors and that determining what is ''best'' depends on how much weight to give the factors. In promulgating certain standards of performance, the EPA may give greater weight to particular factors than it does in promulgating other standards of performance. Thus, the determination of what is ''best'' is complex and necessarily requires an exercise of judgment. By analogy, the question of who is the ''best'' sprinter in the 100-meter dash primarily depends on only one criterion—speed—and therefore is relatively straightforward, whereas the question of who is the ''best'' baseball player depends on a more complex weighing of multiple criteria and therefore requires a greater exercise of judgment.

The term ''best'' also authorizes the EPA to consider factors in addition to the ones enumerated in CAA section 111(a)(1), that further the purpose of the statute. In *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973), the D.C. Circuit held that under CAA section 111(a)(1) as it read prior to the enactment of the 1977 CAA Amendments that added a requirement that the EPA take account of non-air quality environmental impacts, the EPA must consider ''counter-productive environmental effects'' in Determining the BSER. *Id.* at 385. The court elaborated: ''The standard of the 'best system' is comprehensive, and we cannot imagine that Congress intended that 'best' could apply to a system which did more damage to water than it prevented to air.'' *Id.,* n.42. In *Sierra Club* v. *Costle,* 657 F.2d at 326, 346–47, the court added that the EPA must consider the amount of emission reductions and technology advancement in determining BSER, as discussed in section V.C.2.g of this preamble.

The court's view that ''best'' includes additional factors that further the purpose of CAA section 111 is a reasonable interpretation of that term in its statutory context. The purpose of CAA section 111 is to reduce emissions of air pollutants that endanger public health or welfare. CAA section 111(b)(1)(A). The court reasonably surmised that the EPA's determination of whether a system of emission reduction that reduced certain air pollutants is ''best'' should be informed by impacts that the system may have on other pollutants that affect public or welfare. *Portland Cement Ass'n,* 486 F.2d at 385. The Supreme Court confirmed the D.C. Circuit's approach in *Michigan* v. *EPA,* 576 U.S. 743 (2015), explaining that administrative agencies must engage in ''reasoned decisionmaking'' that, in the case of pollution control, cannot be based on technologies that ''do even more damage to human health'' than the emissions they eliminate. *Id.* at 751–52. After *Portland Cement Ass'n,* Congress revised CAA section 111(a)(1) to make explicit that in determining whether a system of emission reduction is the ''best,'' the EPA should account for non-air quality health and environmental impacts. By the same token, the EPA takes the position that in determining whether a system of emission reduction is the ''best,'' the EPA may account for the impacts of the system on air pollutants other than the ones that are the subject of the CAA section 111 regulation.[243] We discuss immediately below other factors that the D.C. Circuit has held the EPA should account for in determining what system is the ''best.''

g. Amount of Emissions Reductions

Consideration of the amount of emissions from the category of sources or the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction'' is implicit in the plain language of CAA section 111(a)(1)—the EPA must choose the *best* system of *emission reduction.* Indeed, consistent with this plain language and the purpose of CAA section 111, the EPA must consider the quantity of emissions at issue. *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[244] The fact that the purpose of a ''system of emission reduction'' is to reduce emissions, and that the term itself explicitly incorporates the concept of reducing emissions, supports the court's view that in determining whether a ''system of emission reduction'' is the ''best,'' the EPA must consider the amount of emission reductions that the system would yield. Even if the EPA were not required to consider the amount of emission reductions, the EPA has the discretion to do so, on grounds that either the term ''system of emission reduction'' or the term ''best'' may reasonably be read to allow that discretion.

h. Expanded Use and Development of Technology

The D.C. Circuit has long held that Congress intended for CAA section 111

---

[240] *Sierra Club* v. *Costle,* 657 F.2d at 319.

[241] *Sierra Club* v. *Costle,* 657 F.2d at 321; *see also New York* v. *Reilly,* 969 F.2d at 1150 (because Congress did not assign the specific weight the Administrator should assign to the statutory elements, ''the Administrator is free to exercise [her] discretion'' in promulgating an NSPS).

[242] *Lignite Energy Council,* 198 F.3d at 933 (paragraphing revised for convenience). *See New York* v. *Reilly,* 969 F.2d 1147, 1150 (D.C. Cir. 1992) (''Because Congress did not assign the specific weight the Administrator should accord each of these factors, the Administrator is free to exercise his discretion in this area.''); *see also NRDC* v. *EPA,* 25 F.3d 1063, 1071 (D.C. Cir. 1994) (The EPA did not err in its final balancing because ''neither RCRA nor EPA's regulations purports to assign any particular weight to the factors listed in subsection (a)(3). That being the case, the Administrator was free to emphasize or deemphasize particular factors, constrained only by the requirements of reasoned agency decisionmaking.'').

[243] See generally *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review—Supplemental Notice of Proposed Rulemaking,* 87 FR 74765 (December 6, 2022) (proposing the BSER for reducing methane and VOC emissions from natural gas-driven controllers in the oil and natural gas sector on the basis of, among other things, impacts on emissions of criteria pollutants). In this preamble, for convenience, the EPA generally discusses the effects of controls on non-GHG air pollutants along with the effects of controls on non-air quality health and environmental impacts.

[244] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system of emission reduction'' to read, ''best technological system of continuous emission reduction.'' As noted above, the 1990 CAAA deleted ''technological'' and ''continuous'' and thereby returned the phrase to how it read under the 1970 CAAA. The court's interpretation of the 1977 CAAA phrase in *Sierra Club* v. *Costle* to require consideration of the amount of air emissions focused on the term ''best,'' and the terms ''technological'' and ''continuous'' were irrelevant to its analysis. It thus remains valid for the 1990 CAAA phrase ''best system of emission reduction.''

to create incentives for new technology and therefore that the EPA is required to consider technological innovation as one of the factors in determining the ''best system of emission reduction.'' *See Sierra Club* v. *Costle,* 657 F.2d at 346–47. The court has grounded its reading in the statutory text of CAA 111(a)(1), defining the term ''standard of performance.'' [245] In addition, the court's interpretation finds support in the legislative history.[246] The legislative history identifies three different ways that Congress designed CAA section 111 to authorize standards of performance that promote technological improvement: (1) The development of technology that may be treated as the ''best system of emission reduction . . . adequately demonstrated;'' under CAA section 111(a)(1); [247] (2) the expanded use of the best demonstrated technology; [248] and (3) the development of emerging technology.[249] Even if the EPA were not required to consider technological innovation as part of its determination of the BSER, it would be reasonable for the EPA to consider it because technological innovation may be considered an element of the term ''best,'' particularly in light of Congress's emphasis on technological innovation.

i. Achievability of the Degree of Emission Limitation

For new sources, CAA section 111(b)(1)(B) and (a)(1) provides that the EPA must establish ''standards of performance,'' which are standards for emissions that reflect the degree of emission limitation that is ''achievable'' through the application of the BSER. A standard of performance is ''achievable'' if a technology can reasonably be projected to be available to an individual source at the time it is constructed that will allow it to meet the standard.[250] Moreover, according to the court, ''[a]n achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption.'' [251] To be achievable, a standard ''must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'costs' of compliance.'' [252] To show a standard is achievable, the EPA must ''(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard.'' [253]

Although the courts have established these standards for achievability in cases concerning CAA section 111(b) new source standards of performance, generally comparable standards for achievability should apply under CAA section 111(d), although the BSER may differ in some cases as between new and existing sources due to, for example, higher costs of retrofit. 40 FR 53340 (November 17, 1975). For existing sources, CAA section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include ''standards of performance.'' As the Supreme Court has recognized, this provision requires the EPA to promulgate emission guidelines that determine the BSER for a source category and then identify the degree of emission limitation achievable by application of the BSER. *See West Virginia* v. *EPA,* 597 U.S. at 710.[254]

The EPA has promulgated emission guidelines on the basis that the existing sources can achieve the degree of emission limitation described therein, even though under the RULOF provision of CAA section 111(d)(1), the state retains discretion to apply standards of performance to individual sources that are less stringent, which indicates that Congress recognized that the EPA may promulgate emission guidelines that are consistent with CAA section 111(d) even though certain individual sources may not be able to achieve the degree of emission limitation identified therein by applying the controls that the EPA determined to be the BSER. Note further that this requirement that the emission limitation be ''achievable'' based on the ''best system of emission reduction . . . adequately demonstrated'' indicates that the technology or other measures that the EPA identifies as the BSER must be technically feasible.

3. EPA Promulgation of Emission Guidelines for States To Establish Standards of Performance

CAA section 111(d)(1) directs the EPA to promulgate regulations establishing a procedure similar to that provided by CAA section 110 under which states submit state plans that establish ''standards of performance'' for emissions of certain air pollutants from sources which, if they were new sources, would be regulated under CAA section 111(b), and that provide for the implementation and enforcement of such standards of performance. The term ''standard of performance'' is defined under CAA section 111(a)(1), quoted above. Thus, CAA sections 111(a)(1) and (d)(1) collectively require the EPA to determine the degree of emission limitation achievable through application of the BSER to existing sources and to establish regulations under which states establish standards of performance reflecting that degree of emission limitation. The EPA addresses both responsibilities through its emission guidelines, as well as through its general implementing regulations for CAA section 111(d). Consistent with the statutory requirements, the general implementing regulations require that the EPA's emission guidelines reflect—

> the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction and any non-air quality health and environmental

[245] *Sierra Club* v. *Costle,* 657 F.2d at 346 (''Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and non-air quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.'').

[246] See S. Rep. No. 91–1196 at 16 (1970) (''Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources''); S. Rep. No. 95–127 at 17 (1977) (cited in *Sierra Club* v. *Costle,* 657 F.2d at 346 n.174) (''The section 111 Standards of Performance . . . sought to assure the use of available technology and to stimulate the development of new technology'').

[247] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (the best system of emission reduction must ''look[ ] toward what may fairly be projected for the regulated future, rather than the state of the art at present'').

[248] 1970 Senate Committee Report No. 91–1196 at 15 (''The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems'').

[249] *Sierra Club* v. *Costle,* 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

[250] *Sierra Club* v. *Costle,* 657 F.2d 298, 364, n.276 (D.C. Cir. 1981).

[251] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433–34 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974).

[252] *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).

[253] *Sierra Club* v. *Costle,* 657 F.2d 298, 377 (D.C. Cir. 1981) (citing *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416 (D.C. Cir. 1980). In considering the representativeness of the source tested, the EPA may consider such variables as the '' 'feedstock, operation, size and age' of the source.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 433 (D.C. Cir. 1980). Moreover, it may be sufficient to ''generalize from a sample of one when one is the only available sample, or when that one is shown to be representative of the regulated industry along relevant parameters.'' *Nat'l Lime Ass'n* v. *EPA,* 627 F.2d 416, 434, n.52 (D.C. Cir. 1980).

[254] 40 CFR 60.21(e), 60.21a(e).

impact and energy requirements) the Administrator has determined has been adequately demonstrated from designated facilities.[255]

Following the EPA's promulgation of emission guidelines, each state must establish standards of performance for its existing sources, which the EPA's regulations call ''designated facilities.'' [256] Such standards of performance must reflect the degree of emission limitation achievable through application of the best system of emission reduction as determined by the EPA, which the Agency may express as a presumptive standard of performance in the applicable emission guidelines.

While the standards of performance that states establish in their plans must generally be no less stringent than the degree of emission limitation determined by the EPA,[257] CAA section 111(d)(1) also requires that the EPA's regulations ''permit the State in applying a standard of performance to any particular source . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' Consistent with this statutory direction, the EPA's general implementing regulations for CAA section 111(d) provide a framework for states' consideration of remaining useful life and other factors (referred to as ''RULOF'') when applying a standard of performance to a particular source. In November 2023, the EPA finalized clarifications to its regulations governing states' consideration of RULOF to apply less stringent standards of performance to particular existing sources. As amended, these regulations provide that states may apply a standard of performance to a particular designated facility that is less stringent than, or has a longer compliance schedule than, otherwise required by the applicable emission guideline taking into consideration that facility's remaining useful life and other factors. To apply a less stringent standard of performance or longer compliance schedule, the state must demonstrate with respect to each facility (or class of such facilities), that the facility cannot reasonably achieve the degree of emission limitation determined by the EPA based on unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility or technical infeasibility of installing necessary control equipment; or other circumstances specific to the facility. In doing so, the state must demonstrate that there are fundamental differences between the information specific to a facility (or class of such facilities) and the information the EPA considered in determining the degree of emission limitation achievable through application of the BSER or the compliance schedule that make achieving such degree of emission reduction or meeting such compliance schedule unreasonable for that facility.

In addition, under CAA section 116, states may establish standard of performances that are more stringent than the presumptive standards of performance contained in the EPA's emission guidelines.[258] The state must include the standards of performance in their state plans and submit the plans to the EPA for review according to the procedures established in the Agency's general implementing regulations for CAA section 111(d).[259] Under CAA section 111(d)(2)(A), the EPA approves state plans that are determined to be ''satisfactory.'' CAA section 111(d)(2)(A) also gives the Agency ''the same authority'' as under CAA section 110(c) to promulgate a Federal plan in cases where a state fails to submit a satisfactory state plan.

VI. ACE Rule Repeal

The EPA is finalizing repeal of the ACE Rule. The EPA proposed to repeal the ACE Rule and did not receive significant comments objecting to the proposal. The EPA is finalizing the proposal largely as proposed. A general summary of the ACE Rule, including its regulatory and judicial history, is included in section V.B.4 of this preamble. The EPA repeals the ACE Rule on three grounds that each independently justify the rule's repeal.

First, as a policy matter, the EPA concludes that the suite of heat rate improvements (HRI) the ACE Rule selected as the BSER is not an appropriate BSER for existing coal-fired EGUs. In the EPA's technical judgment, the suite of HRI set forth in the ACE Rule provide negligible CO_2 reductions at best and, in many cases, may increase CO_2 emissions because of the ''rebound effect,'' as explained in section VII.D.4.a.iii of this preamble. These concerns, along with the EPA's experience in implementing the ACE Rule, cast doubt that the ACE Rule would achieve emission reductions and increase the likelihood that the ACE Rule could make CO_2 pollution worse. As a result, the EPA has determined it is appropriate to repeal the rule, and to reevaluate whether other technologies constitute the BSER.

Second, even assuming the ACE Rule's rejection of CCS and natural gas co-firing was supported at the time, the ACE Rule's rationale for rejecting CCS and natural gas co-firing as the BSER no longer applies because of new factual developments. Since the ACE Rule was promulgated, changes in the power industry, developments in the costs of controls, and new federal subsidies have made other controls more broadly available and less expensive. Considering these developments, the EPA has determined that co-firing with natural gas and CCS are the BSER for certain subcategories of sources as described in section VII.C of this preamble, and that the HRI technologies adopted by the ACE Rule are not the BSER. Thus, repeal of the ACE Rule is proper on this ground as well.

Third, the EPA concludes that the ACE Rule conflicted with CAA section 111 and the EPA's implementing regulations because it did not specifically identify the BSER or the ''degree of emission limitation achievable though application of the [BSER].'' Instead, the ACE Rule described only a broad range of values as the ''degree of emission limitation achievable.'' In doing so, the rule did not provide the states with adequate guidance on the degree of emission limitation that must be reflected in the standards of performance so that a state plan would be approvable by the EPA. The ACE Rule is repealed for this reason also.

A. Summary of Selected Features of the ACE Rule

The ACE Rule determined that the BSER for coal-fired EGUs was a ''list of 'candidate technologies,' '' consisting of seven types of the ''most impactful HRI technologies, equipment upgrades, and best operating and maintenance practices,'' (84 FR 32536; July 8, 2019), including, among others, ''Boiler Feed Pumps'' and ''Redesign/Replace Economizer.'' *Id.* at 32537 (table 1). The rule provided a range of improvements

[255] 40 CFR 60.21a(e).

[256] 40 CFR 60.21a(b), 60.24a(b).

[257] As the Supreme Court explained in *West Virginia* v. *EPA,* ''Although the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d).'' 597 U.S. at 710. The Court elaborated that ''[t]he Agency, not the States, decides the amount of pollution reduction that must ultimately be achieved. It does so by again determining, as when setting the new source rules, 'the best system of emission reduction . . . that has been adequately demonstrated for [existing covered] facilities.' 40 CFR 60.22(b)(5) (2021); see also 80 FR 64664, and n.1. The States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA. See §§ 60.23, 60.24; 42 U.S.C. 7411(d)(1).'' *Id.*

[258] 40 CFR 60.24a(i).

[259] See generally 40 CFR 60.23a–60.28a.

in heat rate that each of the seven ''candidate technologies'' could achieve if applied to coal-fired EGUs of different capacities. For six of the technologies, the expected level of improvement in heat rate ranged from 0.1–0.4 percent to 1.0–2.9 percent, and for the seventh technology, ''Improved Operating and Maintenance (O&M) Practices,'' the range was ''0 to >2%.'' *Id.* The ACE Rule explained that states must review each of their designated facilities, on either a source-by-source or group-of-sources basis, and ''evaluate the applicability of each of the candidate technologies.'' *Id.* at 32550. States were to use the list of HRI technologies ''as guidance but will be expected to conduct unit-specific evaluations of HRI potential, technical feasibility, and applicability for each of the BSER candidate technologies.'' *Id.* at 32538.

The ACE Rule emphasized that states had ''inherent flexibility'' in evaluating candidate technologies with ''a wide range of potential outcomes.'' *Id.* at 32542. The ACE Rule provided that states could conclude that it was not appropriate to apply some technologies. *Id.* at 32550. Moreover, if a state decided to apply a particular technology to a particular source, the state could determine the level of heat rate improvement from the technology could be anywhere within the range that the EPA had identified for that technology, or even outside that range. *Id.* at 32551. The ACE Rule stated that after the state evaluated the technologies and calculated the amount of HRI in this way, it should determine the standard of performance 0that the source could achieve, *Id.* at 32550, and then adjust that standard further based on the application of source-specific factors such as remaining useful life. *Id.* at 32551.

The ACE Rule then identified the process by which states had to take these actions. States must ''evaluat[e] each'' of the seven candidate technologies and provide a summary, which ''include[s] an evaluation of the . . . degree of emission limitation achievable through application of the technologies.'' *Id.* at 32580. Then, the state must provide a variety of information about each power plant, including, the plant's ''annual generation,'' ''CO_2 emissions,'' ''[f]uel use, fuel price, and carbon content,'' ''operation and maintenance costs,'' ''[h]eat rates,'' ''[e]lectric generating capacity,'' and the ''timeline for implementation,'' among other information. *Id.* at 32581. The EPA explained that the purpose of this data was to allow the Agency to ''adequately and appropriately review the plan to determine whether it is satisfactory.'' *Id.* at 32558.

The ACE Rule projected a very low level of overall emission reduction if states generally applied the set of candidate technologies to their sources. The rule was projected to achieve a less-than-1-percent reduction in power-sector CO_2 emissions by 2030.[260] Further, the EPA also projected that it would increase CO_2 emissions from power plants in 15 states and the District of Columbia because of the ''rebound effect'' as coal-fired sources implemented HRI measures and became more efficient. This phenomenon is explained in more detail in section VII.D.4.a.iii of this document.[261]

The ACE Rule considered several other control measures as the BSER, including co-firing with natural gas and CCS, but rejected them. The ACE Rule rejected co-firing with natural gas primarily on grounds that it was too costly in general. 84 FR 32545 (July 8, 2019). The rule also concluded that generating electricity by co-firing natural gas in a utility boiler would be an inefficient use of the gas when compared to combusting it in a combustion turbine. *Id.* The ACE Rule rejected CCS on grounds that it was too costly. *Id.* at 32548. The rule identified the high capital and operating costs of CCS and noted the fact that the IRC section 45Q tax credit, as it then applied, would provide only limited benefit to sources. *Id.* at 32548–49.

B. Developments Undermining ACE Rule's Projected Emission Reductions

The EPA's first basis for repealing the ACE Rule is that it is unlikely that—if implemented—the rule would reduce emissions, and implementation could increase CO_2 emissions instead. Thus, the EPA concludes that as a matter of policy it is appropriate to repeal the rule and evaluate anew whether other technologies qualify as the BSER.

Two factors, taken together, undermine the ACE Rule's projected emission reductions and create the risk that implementation of the ACE Rule could increase—rather than reduce—CO_2 emissions from coal-fired EGUs. First, HRI technologies achieve only limited GHG emission reductions. The ACE Rule projected that if states generally applied the set of candidate technologies to their sources, the rule would achieve a less-than-1-percent reduction in power-sector CO_2 emissions by 2030.[262] The EPA now doubts that even these minimal reductions would be achieved. The ACE Rule's projected benefits were premised in part on a 2009 technical report by Sargent & Lundy that evaluated the effects of HRI technologies. In 2023, Sargent & Lundy issued an updated report which details that the HRI selected as the BSER in the ACE Rule would bring fewer emissions reductions than estimated in 2009. The 2023 report concludes that, with few exceptions, HRI technologies are less effective at reducing CO_2 emissions than assumed in 2009. Further reinforcing the conclusion that HRIs would bring few reductions, the 2023 report also concluded that most sources had already optimized application of HRIs, and so there are fewer opportunities to reduce emissions than previously anticipated.[263]

Second, for a subset of sources, HRI are likely to cause a ''rebound effect'' leading to an increase in GHG emissions for those sources. The rebound effect is explained in detail in section VII.D.4.a.iii of this preamble. The ACE Rule's analysis projected that the rule would increase CO_2 emissions from power plants in 15 states and the District of Columbia. The EPA's modeling projections assumed that, consistent with the rule, some sources would impose a small degree of efficiency improvements. The modeling showed that, as a consequence of these improvements, the rule would increase absolute emissions at some coal-fired sources as these sources became more efficient and displaced lower emitting sources like natural gas-fired EGUs.[264]

Even though the ACE Rule was projected to increase emissions in many states, these states were nevertheless obligated under the rule to assemble detailed state plans that evaluated available technologies and the performance of each existing coal-fired power plant, as described in section IX.A of this preamble. For example, the state was required to analyze the plant's ''annual generation,'' ''CO_2 emissions,'' ''[f]uel use, fuel price, and carbon content,'' ''operation and maintenance

[260] ACE Rule RIA 3–11, table 3–3.

[261] The rebound effect becomes evident by comparing the results of the ACE Rule IPM runs for the 2018 reference case, EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case,* Document ID No. EPA–HQ–OAR–2017–0355–26720, and for the ''Illustrative ACE Scenario. *IPM State-Level Emissions: Illustrative ACE Scenario,* Document ID No. EPA–HQ–OAR–2017–0355–26724.

[262] ACE Rule RIA 3–11, table 3–3.

[263] Sargent and Lundy. Heat Rate Improvement Method Costs and Limitations Memo. Available in Docket ID No. EPA–HQ–OAR–2023–0072.

[264] See EPA, *IPM State-Level Emissions: EPAv6 November 2018 Reference Case,* Document ID No. EPA–HQ–OAR–2017–0355–26720 (providing ACE reference case); *IPM State-Level Emissions: Illustrative ACE Scenario,* Document ID No. EPA–HQ–OAR–2017–0355–26724 (providing illustrative scenario).

costs,'' ''[h]eat rates,'' ''[e]lectric generating capacity,'' and the ''timeline for implementation,'' among other information. 84 FR 32581 (July 8, 2019). The risk of an increase in emissions raises doubts that the HRI for coal-fired sources satisfies the statutory criteria to constitute the BSER for this category of sources. The core element of the BSER analysis is whether the emission reduction technology selected reduces emissions. *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 441 (D.C. Cir. 1973) (noting ''counter productive environmental effects'' raises questions as to whether the BSER selected was in fact the ''best''). Moreover, this evaluation and the imposition of standards of performance was mandated even though the state plan would lead to an *increase* rather than decrease CO_2 emissions. Imposing such an obligation on states under these circumstances was arbitrary.

The EPA's experience in implementing the ACE Rule reinforces these concerns. After the ACE Rule was promulgated, one state drafted a state plan that set forth a standard of performance that allowed the affected source to increase its emission rate. The draft partial plan would have applied to one source, the Longview Power, LLC facility, and would have established a standard of performance, based on the state's consideration of the ''candidate technologies,'' that was higher (*i.e.,* less stringent) than the source's historical emission rate. Thus, the draft plan would not have achieved any emission reductions from the source, and instead would have allowed the source to *increase* its emissions, if it had been finalized.[265]

Because there is doubt that the minimal reductions projected by the ACE Rule would be achieved, and because the rebound effect could lead to an increase in emissions for many sources in many states, the EPA concludes that it is appropriate to repeal the ACE Rule and reevaluate the BSER for this category of sources.

C. Developments Showing That Other Technologies Are the BSER for This Source Category

Since the promulgation of the ACE Rule in 2019, the factual underpinnings of the rule have changed in several ways and lead the EPA to determine that HRI are not the BSER for coal-fired power plants. This reevaluation is consistent with *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009). There, the Supreme Court explained that an agency issuing a new policy ''need not demonstrate to a court's satisfaction that the reasons for the new policy are *better* than the reasons for the old one.'' Instead, ''it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates.'' *Id.* at 514–16 (emphasis in original; citation omitted).

Along with changes in the anticipated reductions from HRI, it makes sense for the EPA to reexamine the BSER because the costs of two control measures, co-firing with natural gas and CCS, have fallen for sources with longer-term operating horizons. As noted, the ACE Rule rejected natural gas co-firing as the BSER on grounds that it was too costly and would lead to inefficient use of natural gas. But as discussed in section VII.C.2.b of this preamble, the costs of natural gas co-firing are presently reasonable, and the EPA concludes that the costs of co-firing 40 percent by volume natural gas are cost-effective for existing coal-fired EGUs that intend to operate after January 1, 2032, and cease operation before January 1, 2039. In addition, changed circumstances—including that natural gas is available in greater amounts, that many coal-fired EGUs have begun co-firing with natural gas or converted wholly to natural-gas, and that there are fewer coal-fired EGUs in operation—mitigate the concerns the ACE Rule identified about inefficient use of natural gas.

Similarly, the ACE Rule rejected CCS as the BSER on grounds that it was too costly. But the costs of CCS have substantially declined, as discussed in section VII.C.1.a.ii of the preamble, partly because of developments in the technology that have lowered capital costs, and partly because the IRA extended and increased the IRS section 45Q tax credit so that it defrays a higher portion of the costs of CCS. Accordingly, for coal-fired EGUs that will continue to operate past 2039, the EPA concludes that the costs of CCS are reasonable, as described in section VII.C.1.a.ii of the preamble.

The emission reductions from these two technologies are substantial. For long-term coal-fired steam generating units, the BSER of 90 percent capture CCS results in substantial CO_2 emissions reductions amounting to emission rates that are 88.4 percent lower on a lb/MWh-gross basis and 87.1 percent lower on a lb/MWh-net basis compared to units without capture, as described in section VII.C.2.b.iv of this preamble. For medium term units, the BSER of 40 percent natural gas co-firing achieves CO_2 stack emissions reductions of 16 percent, as described in section VII.C.2.b.iv of this preamble. Given the availability of more effective, cost-reasonable technology, the EPA concludes that HRIs are not the BSER for all coal-fired EGUs.

The EPA is thus finalizing a new policy for coal-fired power plants. This rule applies to those sources that intend to operate past January 1, 2032. For sources that intend to cease operations after January 1, 2032, but before January 1, 2039, the EPA concludes that the BSER is co-firing 40 percent by volume natural gas. The EPA concludes this control measure is appropriate because it achieves substantial reductions at reasonable cost. In addition, the EPA believes that because a large supply of natural gas is available, devoting part of this supply for fuel for a coal-fired steam generating unit in place of a percentage of the coal burned at the unit is an appropriate use of natural gas and will not adversely impact the energy system, as described in section VII.C.2.b.iii(B) of this preamble. For sources that intend to operate past January 1, 2039, the EPA concludes that the BSER is CCS with 90 percent capture of CO_2. The EPA believes that this control measure is appropriate because it achieves substantial reductions at reasonable cost, as described in section VII.C.1 of this preamble.

The EPA is not concluding that HRI is the BSER for any coal-fired EGUs. As discussed in section VII.D.4.a, the EPA does not consider HRIs an appropriate BSER for coal-fired EGUs because these technologies would achieve few, if any, emissions reductions and may increase emissions due to the rebound effect. Most importantly, changed circumstances show that co-firing natural gas and CCS are available at reasonable cost, and will achieve more GHG emissions reductions. Accordingly, the EPA believes that HRI do not qualify as the BSER for any coal-fired EGUs, and that other approaches meet the statutory standard. On this basis, the EPA repeals the ACE Rule.

D. Insufficiently Precise Degree of Emission Limitation Achievable From Application of the BSER

The third independent reason why the EPA is repealing the ACE Rule is that the rule did not identify with sufficient specificity the BSER or the degree of emission limitation achievable through the application of the BSER. Thus, states lacked adequate guidance on the BSER they should consider and

[265] West Virginia CAA § 111(d) Partial Plan for Greenhouse Gas Emissions from Existing Electric Utility Generating Units (EGUs), *https://dep.wv.gov/daq/publicnoticeandcomment/Documents/Proposed%20WV%20ACE%20State%20Partial%20Plan.pdf.*

level of emission reduction that the standards of performance must achieve. The ACE Rule determined the BSER to be a suite of HRI ''candidate technologies,'' but did not identify with specificity the degree of emission limitation states should apply in developing standards of performance for their sources. As a result, the ACE Rule conflicted with CAA section 111 and the implementing regulations, and thus failed to provide states adequate guidance so that they could ensure that their state plans were satisfactory and approvable by the EPA.

CAA section 111 and the EPA's longstanding implementing regulations establish a clear process for the EPA and states to regulate emissions of certain air pollutants from existing sources. ''The statute directs the EPA to (1) 'determine[ ],' taking into account various factors, the 'best system of emission reduction which . . . has been adequately demonstrated,' (2) ascertain the 'degree of emission limitation achievable through the application' of that system, and (3) impose an emissions limit on new stationary sources that 'reflects' that amount.'' *West Virginia* v. *EPA,* 597 U.S. at 709 (quoting 42 U.S.C. 7411(d)). Further, ''[a]lthough the States set the actual rules governing existing power plants, EPA itself still retains the primary regulatory role in Section 111(d) . . . [and] decides the amount of pollution reduction that must ultimately be achieved.'' *Id.* at 2602.

Once the EPA makes these determinations, the state must establish ''standards of performance'' for its sources that are based on the degree of emission limitation that the EPA determines in the emission guidelines. CAA section 111(a)(1) makes this clear through its definition of ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER].'' After the EPA determines the BSER, 40 CFR 60.22(b)(5), and the degree of emission limitation achievable from application of the BSER, ''the States then submit plans containing the emissions restrictions that they intend to adopt and enforce in order not to exceed the permissible level of pollution established by EPA.'' 597 U.S. at 710 (citing 40 CFR 60.23, 60.24; 42 U.S.C. 7411(d)(1)).

The EPA then reviews the plan and approves it if the standards of performance are ''satisfactory,'' under CAA section 111(d)(2)(A). The EPA's longstanding implementing regulations make clear that the EPA's basis for determining whether the plan is ''satisfactory'' includes that the plan must contain ''emission standards . . . no less stringent than the corresponding emission guideline(s).'' 40 CFR 60.24(c), 40 CFR 60.24a(c). In addition, under CAA section 111(d)(1), in ''applying a standard of performance to any particular source'' a state may consider, ''among other factors, the remaining useful life of the existing source to which such standard applies.'' This is also known as the RULOF provision and is discussed in section X.C.2 of this preamble.

In the ACE Rule, the EPA recognized that the CAA required it to determine the BSER and identify the degree of emission limitation achievable through application of the BSER. 84 FR 32537 (July 8, 2019). But the rule did not make those determinations. Rather, the ACE Rule described the BSER as a list of ''candidate technologies.'' And the rule described the degree of emission limitation achievable by application of the BSER as ranges of reductions from the HRI technologies. The rule thus shifted the responsibility for determining the BSER and degree of emission limitation achievable from the EPA to the states. Accordingly, the ACE Rule did not meet the CAA section 111 requirement that the EPA determine the BSER or the degree of emission limitation from application of the BSER.

As described above, the ACE Rule identified the HRI in the form of a list of seven ''candidate technologies,'' accompanied by a wide range of percentage improvements to heat rate that these technologies could provide. Indeed, for one of them, improved ''O&M'' practices (that is, operation and management practices), the range was ''0 to >2%,'' which is effectively unbounded. 84 FR 32537 (table 1) (July 8, 2019). The ACE Rule was clear that this list was simply the starting point for a state to calculate the standards of performance for its sources. That is, the seven sets of technologies were ''candidate[s]'' that the state could apply to determine the standard of performance for a source, and if the state did choose to apply one or more of them, the state could do so in a manner that yielded any percentage of heat rate improvement within the range that the EPA identified, or even outside that range. Thus, as a practical matter, the ACE Rule did not determine the BSER or any degree of emission limitation from application of the BSER, and so states had no guidance on how to craft approvable state plans. In this way, the ACE Rule did not adhere to the applicable statutory obligations. See 84 FR 32537–38 (July 8, 2019).

The only constraints that the ACE Rule imposed on the states were procedural ones, and those did not give the EPA any benchmark to determine whether a plan could be approved or give the states any certainty on whether their plan would be approved. As noted above, when a state submitted its plan, it needed to show that it evaluated each candidate technology for each source or group of sources, explain how it determined the degree of emission limitation achievable, and include data about the sources. But because the ACE Rule did not identify a BSER or include a degree of emission limitation that the standards must reflect, the states lacked specific guidance on how to craft adequate standards of performance, and the EPA had no benchmark against which to evaluate whether a state's submission was ''satisfactory'' under CAA section 111(d)(2)(A). Thus, the EPA's review of state plans would be essentially a standardless exercise, notwithstanding the Agency's longstanding view that it was ''essential'' that ''EPA review . . . [state] plans for their substantive adequacy.'' 40 FR 53342–43 (November 17, 1975). In 1975, the EPA explained that it was not appropriate to limit its review based ''solely on procedural criteria'' because otherwise ''states could set extremely lenient standards . . . so long as EPA's procedural requirements were met.'' *Id.* at 53343.

Finally, the ACE Rule's approach to determining the BSER and degree of emission limitation departed from prior emission guidelines under CAA section 111(d), in which the EPA included a numeric degree of emission limitation. See, *e.g.,* 42 FR 55796, 55797 (October 18, 1977) (limiting emission rate of acid mist from sulfuric acid plants to 0.25 grams per kilogram of acid); 44 FR 29829 (May 22, 1979) (limiting concentrations of total reduced sulfur from most of the subcategories of kraft pulp mills, such as digester systems and lime kilns, to 5, 20, or 25 ppm over 12-hour averages); 61 FR 9919 (March 12, 1996) (limiting concentration of non-methane organic compounds from solid waste landfills to 20 parts per million by volume or a 98 percent reduction). The ACE Rule did not grapple with this change in position as required by *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009), or explain why it was appropriate to provide a boundless degree of emission limitation achievable in this context.

The EPA is finalizing the repeal the ACE Rule on this ground as well. The ACE Rule's failure to determine the BSER and the associated degree of emission limitation achievable from

application of the BSER deviated from CAA section 111 and the implementing regulations. Without these determinations, the ACE Rule lacked any benchmark that would guide the states in developing their state plans, and by which the EPA could determine whether those state plans were satisfactory.

For each of these three, independent reasons, repeal of the ACE Rule is proper.

E. Withdrawal of Proposed NSR Revisions

In addition to repealing the ACE Rule, the Agency is withdrawing the proposed revisions to the NSR applicability provisions that were included the ACE Rule proposal (83 FR 44756, 44773–83; August 31, 2018). These proposed revisions would have included an hourly emissions rate test to determine NSR applicability for a modified EGU, with the expressed purpose of alleviating permitting burdens for sources undertaking HRI projects pursuant to the ACE Rule emission guidelines. The ACE Rule final action did not include the NSR revisions, and the EPA indicated in that preamble that it intended to take final action on the NSR proposal in a separate action at a later date. However, the EPA did not take a final action on the NSR revisions, and the EPA has decided to no longer pursue them and to withdraw the proposed revisions.

Withdrawal of the proposal to establish an hourly emissions test for NSR applicability for EGUs is appropriate because of the repeal of the ACE rule and the EPA's conclusion that HRI is not the BSER for coal-fired EGUs. The EPA's basis for proposing the NSR revisions was to ease permitting burdens for state agencies and sources that may result from implementing the ACE Rule. There was concern that, for sources that modified their EGU to improve the heat rate, if a source were to be dispatched more frequently because of improved efficiency (the ''rebound effect''), the source could experience an increase in absolute emissions for one or more pollutants and potentially trigger major NSR requirements. The hourly emissions rate test was proposed to relieve such sources that were undertaking HRI projects to comply with their state plans from the burdens of NSR permitting, particularly in cases in which a source has an increase in annual emissions of a pollutant. However, given that this final rule BSER is not based on HRIs for coal-fired EGUs, the NSR revisions proposed as part of the ACE Rule would no longer serve the purpose that the EPA expressed in that proposal preamble.

Furthermore, in the event that any sources are increasing their absolute emissions after modifying an EGU, applicability of the NSR program is beneficial as a backstop that provides review of those situations to determine if additional controls or other emission limitations are necessary on a case-by-case basis to protect air quality. In addition, given that considerable time has passed since these EGU-specific NSR applicability revisions were proposed in 2018, should the EPA decide to pursue them at a later time, it is prudent for the Agency to propose them again at that time, accompanied with the EPA's updated context and justification to support re-proposing the NSR revisions, rather than relying on the proposal from 2018. Therefore, the EPA is withdrawing these proposed NSR revisions.

VII. Regulatory Approach for Existing Fossil Fuel-Fired Steam Generating Units

Existing fossil fuel-fired steam generation units are the largest stationary source of CO_2 emissions, emitting 909 MMT CO_2e in 2021. Recent developments in control technologies offer opportunities to reduce CO_2 emissions from these sources. The EPA's regulatory approach for these units is to require emissions reduction consistent with these technologies, where their use is cost-reasonable.

A. Overview

In this section of the preamble, the EPA identifies the BSER and degree of emission limitation achievable for the regulation of GHG emissions from existing fossil fuel-fired steam generating units. As detailed in section V of this preamble, to meet the requirements of CAA section 111(d), the EPA promulgates ''emission guidelines'' that identify the BSER and the degree of emission limitation achievable through the application of the BSER, and states then establish standards of performance for affected sources that reflect that level of stringency. To determine the BSER for a source category, the EPA identifies systems of emission reduction (*e.g.,* control technologies) that have been adequately demonstrated and evaluates the potential emissions reduction, costs, any non-air health and environmental impacts, and energy requirements. As described in section V.C.1 of this preamble, the EPA has broad authority to create subcategories under CAA section 111(d). Therefore, where the sources in a category differ from each other by some characteristic that is relevant for the suitability of the emission controls, the EPA may create separate subcategories and make separate BSER determinations for those subcategories.

The EPA considered the characteristics of fossil fuel-fired steam generating units that may impact the suitability of different control measures. First, the EPA observed that the type and amounts of fossil fuels—coal, oil, and natural gas—fired in the steam generating unit affect the performance and emissions reductions achievable by different control technologies, in part due to the differences in the carbon content of those fuels. The EPA recognized that many sources fire multiple types of fossil fuel. Therefore, the EPA is finalizing subcategories of coal-fired, oil-fired, and natural gas-fired steam generating units. The EPA is basing these subcategories, in part, on the amount of fuel combusted by the steam generating unit.

The EPA then considered the BSER that may be suitable for each of those subcategories of fuel type. For coal-fired steam generating units, of the available control technologies, the EPA is determining that CCS with 90 percent capture of CO_2 meets the requirements for BSER, including being adequately demonstrated and achieving significant emission reductions at reasonable cost for units operating in the long-term, as detailed in section VII.C.1.a of this preamble. Application of this BSER results in a degree of emission limitation equivalent to an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross). The compliance date for these sources is January 1, 2032.

Typically, the EPA assumes that sources subject to controls operate in the long-term.[266] See, for example, the 2015 NSPS (80 FR 64509; October 23, 2015) or the 2011 CSAPR (76 FR 48208; August 8, 2011). Under that assumption, fleet average costs for CCS are comparable to the cost metrics the EPA has previously considered to be reasonable. However, the EPA observes that about half of the capacity (87 GW out of 181 GW) of existing coal-fired steam generating units have announced plans to permanently cease operation prior to 2039, as detailed in section IV.D.3.b of this preamble, affecting the period available for those sources to amortize the capital costs of CCS.

[266] Typically, the EPA assumes that the capital costs can be amortized over a period of 15 years. As discussed in section VII.C.1.a.ii of this preamble, in the case of CCS, the IRC section 45Q tax credit, which defrays a significant portion of the costs of CCS, is available for the first 12 years of operation. Accordingly, EPA generally assumed a 12-year amortization period in determining CCS costs.

Accordingly, the EPA evaluated the costs of CCS for different amortization periods. For an amortization period of more than 7 years—such that sources operate after January 1, 2039—annualized fleet average costs are comparable to or less than the metrics of costs for controls that the EPA has previously found to be reasonable. However, the group of sources ceasing operation prior to January 1, 2039, have less time available to amortize the capital costs of CCS, resulting in higher annualized costs.

Because the costs of CCS depend on the available amortization period, the EPA is creating a subcategory for sources demonstrating that they plan to permanently cease operation prior to January 1, 2039. Instead, for this subcategory of sources, the EPA is determining that natural gas co-firing at 40 percent of annual heat input meets the requirements of BSER. Application of the natural gas co-firing BSER results in a degree of emission limitation equivalent to a 16 percent reduction in emission rate (lb CO_2/MWh-gross). Co-firing at 40 percent entails significantly less control equipment and infrastructure than CCS, and as a result, the EPA has determined that affected sources are able to implement it more quickly than CCS, by January 1, 2030. Importantly, co-firing at 40 percent also entails significantly less capital cost than CCS, and as a result, the costs of co-firing are comparable to or less than the metrics for cost reasonableness with an amortization period that is significantly shorter than the period for CCS. The EPA has determined that the costs of co-firing meet the metrics for cost reasonableness for the majority of the capacity that permanently cease operation more than 2 years after the January 1, 2030, implementation date, or after January 1, 2032 (and up to December 31, 2038), and that therefore have an amortization period of more than 2 years (and up to 9 years).

The EPA is also determining that sources demonstrating that they plan to permanently cease operation before January 1, 2032, are not subject to the 40 percent co-firing requirement. This is because their amortization period would be so short—2 years or less—that the costs of co-firing would, in general, be less comparable to the cost metrics for reasonableness for that group of sources. Accordingly, the EPA is defining the medium-term subcategory to include those sources demonstrating that they plan to permanently cease operating after December 31, 2031, and before January 1, 2039.

Considering the limited emission reductions available in light of the cost reasonableness of controls with short amortization periods, the EPA is finalizing an applicability exemption for coal-fired steam generating units demonstrating that they plan to permanently cease operation before January 1, 2032.

For natural gas- and oil-fired steam generating units, the EPA is finalizing subcategories based on capacity factor. Because natural gas- and oil-fired steam generating units with similar annual capacity factors perform similarly to one another, the EPA is finalizing a BSER of routine methods of operation and maintenance and a degree of emission limitation of no increase in emission rate for intermediate and base load subcategories. For low load natural gas- and oil-fired steam generating units, the EPA is finalizing a BSER of uniform fuels and respective degrees of emission limitation defined on a heat input basis (130 lb CO_2/MMBtu and 170 lb CO_2/MMBtu). Furthermore, the EPA is finalizing presumptive standards for natural gas- and oil-fired steam generating units as follows: base load sources (those with annual capacity factors greater than 45 percent) have a presumptive standard of 1,400 lb CO_2/MWh-gross, intermediate load sources (those with annual capacity factors greater than 8 percent and or less than or equal to 45 percent) have a presumptive standard of 1,600 lb CO_2/MWh-gross. For low load oil-fired sources, the EPA is finalizing a presumptive standard of 170 lb CO_2/MMBtu, while for low load natural gas-fired sources the EPA is finalizing a presumptive standard of 130 lb CO_2/MMBtu. A compliance date of January 1, 2030, applies for all natural gas- and oil-fired steam generating units.

The final subcategories and BSER are summarized in table 1 of this document.

TABLE 1—SUMMARY OF FINAL BSER, SUBCATEGORIES, AND DEGREES OF EMISSION LIMITATION FOR AFFECTED EGUS

Affected EGUs	Subcategory definition	BSER	Degree of emission limitation	Presumptively approvable standard of performance *
Long-term existing coal-fired steam generating units.	Coal-fired steam generating units that are not medium-term units.	CCS with 90 percent capture of CO_2.	88.4 percent reduction in emission rate (lb CO_2/MWh-gross).	88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.
Medium-term existing coal-fired steam generating units.	Coal-fired steam generating units that have demonstrated that they plan to permanently cease operations after December 31, 2031, and before January 1, 2039.	Natural gas co-firing at 40 percent of the heat input to the unit.	A 16 percent reduction in emission rate (lb CO_2/MWh-gross).	A 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.
Base load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,400 lb CO_2/MWh-gross.
Intermediate load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,600 lb CO_2/MWh-gross.
Low load existing oil-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor less than 8 percent.	lower-emitting fuels	170 lb CO_2/MMBtu	170 lb CO_2/MMBtu.
Base load existing natural gas-fired steam generating units.	Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,400 lb CO_2/MWh-gross.
Intermediate load existing natural gas-fired steam generating units.	Natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.	Routine methods of operation and maintenance.	No increase in emission rate (lb CO_2/MWh-gross).	An annual emission rate limit of 1,600 lb CO_2/MWh-gross.

TABLE 1—SUMMARY OF FINAL BSER, SUBCATEGORIES, AND DEGREES OF EMISSION LIMITATION FOR AFFECTED EGUS—Continued

Affected EGUs	Subcategory definition	BSER	Degree of emission limitation	Presumptively approvable standard of performance *
Low load existing natural gas-fired steam generating units.	Oil-fired steam generating units with an annual capacity factor less than 8 percent.	lower-emitting fuels	130 lb CO_2/MMBtu	130 lb CO_2/MMBtu.

* Presumptive standards of performance are discussed in detail in section X of the preamble. While states establish standards of performance for sources, the EPA provides presumptively approvable standards of performance based on the degree of emission limitation achievable through application of the BSER for each subcategory. Inclusion in this table is for completeness.

B. Applicability Requirements and Fossil Fuel-Type Definitions for Subcategories of Steam Generating Units

In this section of the preamble, the EPA describes the rationale for the final applicability requirements for existing fossil fuel-fired steam generating units. The EPA also describes the rationale for the fuel type definitions and associated subcategories.

1. Applicability Requirements

For the emission guidelines, the EPA is finalizing that a designated facility [267] is any fossil fuel-fired electric utility steam generating unit (*i.e.,* utility boiler or IGCC unit) that: (1) was in operation or had commenced construction on or before January 8, 2014; [268] (2) serves a generator capable of selling greater than 25 MW to a utility power distribution system; and (3) has a base load rating greater than 260 GJ/h (250 million British thermal units per hour (MMBtu/h)) heat input of fossil fuel (either alone or in combination with any other fuel). Consistent with the implementing regulations, the term ''designated facility'' is used throughout this preamble to refer to the sources affected by these emission guidelines.[269] For the emission guidelines, consistent with prior CAA section 111 rulemakings concerning EGUs, the term ''designated facility'' refers to a single EGU that is affected by these emission guidelines. The rationale for the final applicability requirements is the same as that for 40 CFR part 60, subpart TTTT (80 FR 64543–44; October 23, 2015). The EPA includes that discussion by reference here.

Section 111(a)(6) of the CAA defines an ''existing source'' as ''any stationary source other than a new source.'' Therefore, the emission guidelines do not apply to any steam generating units that are new after January 8, 2014, or reconstructed after June 18, 2014, the applicability dates of 40 CFR part 60, subpart TTTT. Moreover, because the EPA is now finalizing revised standards of performance for coal-fired steam generating units that undertake a modification, a modified coal-fired steam generating unit would be considered ''new,'' and therefore not subject to these emission guidelines, if the modification occurs after the date the proposal was published in the **Federal Register** (May 23, 2023). Any coal-fired steam generating unit that has modified prior to that date would be considered an existing source that is subject to these emission guidelines.

In addition, the EPA is finalizing in the applicability requirements of the emission guidelines many of the same exemptions as discussed for 40 CFR part 60, subpart TTTT, in section VIII.E.1 of this preamble. EGUs that may be excluded from the requirement to establish standards under a state plan are: (1) units that are subject to 40 CFR part 60, subpart TTTT, as a result of commencing a qualifying modification or reconstruction; (2) steam generating units subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh; (3) non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor; (4) combined heat and power (CHP) units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater; (5) units that serve a generator along with other affected EGU(s), where the effective generation capacity (determined based on a prorated output of the base load rating of EGU) is 25 MW or less; (6) municipal waste combustor units subject to 40 CFR part 60, subpart Eb; (7) commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; (8) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU; or (9) coal-fired steam generating units that have elected to permanently cease operation prior to January 1, 2032.

The exemptions listed above at (4), (5), (6), and (7) are among the current exemptions at 40 CFR 60.5509(b), as discussed in section VIII.E.1 of this preamble. The exemptions listed above at (2), (3), and (8) are exemptions the EPA is finalizing revisions for 40 CFR part 60, subpart TTTT, and the rationale for the exemptions is in section VIII.E.1 of this preamble. For consistency with the applicability requirements in 40 CFR part 60, subpart TTTT, and 40 CFR part 60, subpart TTTTa, the Agency is finalizing these same exemptions for the applicability of the emission guidelines.

2. Coal-Fired Units Permanently Ceasing Operation Before January 1, 2032

The EPA is not addressing existing coal-fired steam generating units demonstrating that they plan to permanently cease operating before January 1, 2032, in these emission guidelines. Sources ceasing operation before that date have far less emission reduction potential than sources that will be operating longer, because there are unlikely to be appreciable, cost-reasonable emission reductions available on average for the group of sources operating in that timeframe. This is because controls that entail capital expenditures are unlikely to be

[267] The term ''designated facility'' means ''any existing facility . . . which emits a designated pollutant and which would be subject to a standard of performance for that pollutant if the existing facility were an affected facility.'' See 40 CFR 60.21a(b).

[268] Under CAA section 111, the determination of whether a source is a new source or an existing source (and thus potentially a designated facility) is based on the date that the EPA proposes to establish standards of performance for new sources.

[269] The EPA recognizes, however, that the word ''facility'' is often understood colloquially to refer to a single power plant, which may have one or more EGUs co-located within the plant's boundaries.

of reasonable cost for these sources due to the relatively short period over which they could amortize the capital costs of controls.

In particular, in developing the emission guidelines, the EPA evaluated two systems of emission reduction that achieve substantial emission reductions for coal-fired steam generating units: CCS with 90 percent capture; and natural gas co-firing at 40 percent of heat input. For CCS, the EPA has determined that controls can be installed and fully operational by the compliance date of January 1, 2032, as detailed in section VII.C.1.a.i(E) of this preamble. CCS would therefore, in most cases, be unavailable to coal-fired steam generating units planning to cease operation prior to that date. Furthermore, the EPA evaluated the costs of CCS for different amortization periods. For an amortization period of more than 7 years—such that sources operate after January 1, 2039—annualized fleet average costs are comparable to or less than the costs of controls the EPA has previously determined to be reasonable ($18.50/MWh of generation and $98/ton of CO_2 reduced), as detailed in section VII.C.1.a.ii of this preamble. However, the costs for shorter amortization periods are higher. For sources ceasing operation by January 1, 2032, it would be unlikely that the annualized costs of CCS would be reasonable even were CCS installed at an earlier date (*e.g.,* by January 1, 2030) due to the shorter amortization period available.

Because the costs of CCS would be higher for shorter amortization periods, the EPA is finalizing a separate subcategory for sources demonstrating that they plan to permanently cease operating by January 1, 2039, with a BSER of 40 percent natural gas co-firing, as detailed in section VII.C.2.b.ii of this preamble. For natural gas co-firing, the EPA is finalizing a compliance date of January 1, 2030, as detailed in section VII.C.2.b.i(C) of this preamble. Therefore, the EPA assumes sources subject to a natural gas co-firing BSER can amortize costs for a period of up to 9 years. The EPA has determined that the costs of natural gas co-firing at 40 percent meet the metrics for cost reasonableness for the majority of the capacity that operate more than 2 years after the January 1, 2030, implementation date, *i.e.,* that operate after January 1, 2032 (and up to December 31, 2038), and that therefore have an amortization period of more than 2 years (and up to 9 years).

However, for sources ceasing operation prior to January 1, 2032, the EPA believes that establishing a best system of emission reduction corresponding to a substantial level of natural gas co-firing would broadly entail costs of control that are above those that the EPA is generally considering reasonable. Sources permanently ceasing operation before January 1, 2032 would have less than 2 years to amortize the capital costs, as detailed in section VII.C.2.a of this preamble. Compared to the metrics for cost reasonableness that EPA has previously deemed reasonable ($18.50/MWh of generation and $98/ton of CO_2 reduced), very few sources can co-fire 40 percent natural gas at costs comparable to these metrics with an amortization period of only one year; only 1 percent of units have costs that are below both $18.50/MWh of generation and $98/ton of CO_2 reduced. The number of sources that can co-fire lower amounts of natural gas at costs comparable to these metrics is likewise limited—only approximately 34 percent of units can co-fire with 20 percent natural gas at costs lower than both cost metrics. Furthermore, the period that these sources would operate with co-firing for would be short, so that the emission reductions from that group of sources would be limited.

By contrast, assuming a two-year amortization period, many more units can co-fire with meaningful amounts of natural gas at a cost that is consistent with the metrics EPA has previously used: 18 percent of units can co-fire with 40 percent natural gas at costs less than $98/ton and $18.50/MWh, and 50 percent of units can co-fire with 20 percent natural gas at costs lower than both metrics. Because a substantial number of sources can implement 40-percent co-firing with natural gas with an amortization period of two years or longer with reasonable costs, and even more can co-fire with lesser amounts with reasonable costs with amortization periods longer than two years,[270] the EPA determined that a technology-based BSER was available for coal-fired units operating past January 1, 2032.

Sources that retire before that date, however, are differently situated as described above. In light of the small number of sources that are planning to retire before January 1, 2032 that could cost-effectively co-fire with natural gas, coupled with the small amount of emissions reductions that can be achieved from co-firing in such a short time span, the EPA is choosing not to establish a BSER for these sources.[271]

Because, at this time, the EPA has determined that CCS and natural gas co-firing are not available at reasonable cost for sources ceasing operation before January 1, 2032, the EPA is not finalizing a BSER for such sources. Not finalizing a BSER for these sources is consistent with the Agency's discretion to take incremental steps to address CO_2 from sources in the category, and to direct the EPA's limited resources at regulation of those sources that can achieve the most emission reductions. The EPA is therefore providing that existing coal-fired steam generating EGUs that have elected to cease operating before January 1, 2032, are not regulated by these emission guidelines. This exemption applies to a source until the earlier of December 31, 2031, or the date it demonstrates in the state plan that it plans to cease operation. If a source continues to operate past this date, it is no longer exempt from these emission guidelines. See section X.E.1 of this preamble for discussion of how state plans should address sources subject to exemption (9).[272]

3. Sources Outside of the Contiguous U.S.

The EPA proposed the same emission guidelines for fossil fuel-fired steam

[270] As described in detail in section X.C.2 of this preamble, the EPA recognizes that particular affected EGUs may have characteristics that make it unreasonable to achieve the degree of emission limitation corresponding to 40 percent co-firing with natural gas. For example, a state may be able to demonstrate a fundamental difference between the costs the EPA considered in these emission guidelines and the costs to an affected EGU that plans to cease operation in late 2032. If such costs make it unreasonable for a particular unit to meet the degree of emission limitation corresponding to 40 percent co-firing with natural gas, the state may apply a less stringent standard of performance to that unit. Consistent with the requirements for calculating a less stringent standard of performance at 40 CFR 60.24a(f), under these emission guidelines states would consider whether it is reasonable for units that cannot cost-reasonably co-fire natural gas at 40 percent to co-fire at levels lower than 40 percent. It is thus appropriate that coal-fired EGUs that can reasonably co-fire any amount of natural gas be subject to these emission guidelines.

[271] For the reasons described at length in section VI.B, the EPA does not believe that heat rate improvement measures or HRI are appropriate for sources retiring before January 1, 2032 because HRI applied to coal-fired sources achieve few emission reductions, and can lead to the ''rebound effect'' where CO_2 emissions from the source increase rather than decrease as a consequence of imposing the technologies.

[272] The EPA notes that this applicability exemption does not conflict with states' ability to consider the remaining useful lives of ''particular'' sources that are subject to these emission guidelines. 42 U.S.C. 7411(d)(1). As the EPA's implementing regulations specify, the provision for states' consideration of RULOF is intended address the specific conditions of particular sources, whereas the EPA is responsible for determining generally how to regulate a source category under an emission guideline. Moreover, RULOF applies only to when a state is applying a standard of performance to an affected source—and the state would not apply a standard of performance to exempted sources.

generating units in non-continental areas (*i.e.,* Hawaii, the U.S. Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) and non-contiguous areas (non-continental areas and Alaska) as the EPA proposed for comparable units in the contiguous 48 states. The EPA notes that the modeling that supports the final emission guidelines focus on sources in the contiguous U.S. Further, the EPA notes that few, if any, coal-fired steam generating units operate outside of the contiguous 48 states and meet the applicability criteria. Finally, the EPA notes that the proposed BSER and degree of emissions limitation for non-continental oil-fired steam generating units would have achieved few emission reductions. Therefore, the EPA is not finalizing emission guidelines for existing steam generating units in states and territories (including Alaska, Hawaii, Guam, Puerto Rico, and the U.S. Virgin Islands) that are outside of the contiguous U.S. at this time.

4. IGCC Units

The EPA notes that existing IGCC units were included in the proposed applicability requirements and that, in section VII.B of this preamble, the EPA is finalizing inclusion of those units in the subcategory of coal-fired steam generating units. IGCC units gasify coal or solid fossil fuel (*e.g.,* pet coke) to produce syngas (a mixture of carbon monoxide and hydrogen), and either burn the syngas directly in a combined cycle unit or use a catalyst for water-gas shift (WGS) to produce a pre-combustion gas stream with a higher concentration of CO_2 and hydrogen, which can be burned in a hydrogen turbine combined cycle unit. As described in section VII.C of this preamble, the final BSER for coal-fired steam generating units includes co-firing natural gas and CCS. The few IGCC units that now operate in the U.S. either burn natural gas exclusively—and as such operate as natural gas combined cycle units—or in amounts near to the 40 percent level of the natural gas co-firing BSER. Additionally, IGCC units may be suitable for pre-combustion CO_2 capture. Because the CO_2 concentration in the pre-combustion gas, after WGS, is high relative to coal-combustion flue gas, pre-combustion CO_2 capture for IGCC units can be performed using either an amine-based (or other solvent-based) capture process or a physical absorption capture process. Alternatively, post-combustion CO_2 capture can be applied to the source. The one existing IGCC unit that still uses coal was recently awarded funding from DOE for a front-end engineering design (FEED) study for CCS targeting a capture efficiency of more than 95 percent.[273] For these reasons, the EPA is not distinguishing IGCC units from other coal-fired steam generating EGUs, so that the BSER of co-firing for medium-term coal-fired units and CCS for long-term coal-fired units apply to IGCC units.[274]

5. Fossil Fuel-Type Definitions for Subcategories of Steam Generating Units

In this action, the EPA is finalizing definitions for subcategories of existing fossil fuel-fired steam generating units based on the type and amount of fossil fuel used in the unit. The EPA is finalizing separate subcategories based on fuel type because the carbon content of the fuel combusted affects the output emission rate (*i.e.,* lb CO_2/MWh). Fuels with a higher carbon content produce a greater amount of CO_2 emissions per unit of fuel combusted (on a heat input basis, MMBtu) and per unit of electricity generated (*i.e.,* MWh).

The EPA proposed fossil fuel type subcategory definitions based on the definitions in 40 CFR part 63, subpart UUUUU, and the fossil fuel definitions in 40 CFR part 60, subpart TTTT. Those proposed definitions were determined by the relative heat input contribution of the different fuels combusted in a unit during the 3 years prior to the proposed compliance date of January 1, 2030. Further, to be considered an oil-fired or natural gas-fired unit for purposes of this emission guideline, a source would no longer retain the capability to fire coal after December 31, 2029.

The EPA proposed a 3-year lookback period, so that the proposed fuel-type subcategorization would have been based, in part, on the fuel type fired between January 1, 2027, and January 1, 2030. However, the intent of the proposed fuel type subcategorization was to base the fuel type definition on the state of the source on January 1, 2030. Therefore, the EPA is finalizing the following fuel type subcategory definitions:

- A *coal-fired steam generating unit* is an electric utility steam generating unit or IGCC unit that meets the definition of ''fossil fuel-fired'' and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029, or that retains the capability to fire coal after December 31, 2029.
- An *oil-fired steam generating unit* is an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns oil for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.
- A *natural gas-fired steam generating unit* is an electric utility steam generating unit meeting the definition of ''fossil fuel-fired,'' that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.

The EPA received some comments on the fuel type definitions. Those comments and responses are as follows.

Comment: Some industry stakeholders suggested changes to the proposed definitions for fossil fuel type. Specifically, some commenters requested that the reference to the initial compliance date be removed and that the fuel type determination should instead be rolling and continually update after the initial compliance date. Those commenters suggested this would, for example, allow sources in the coal-fired subcategory that begin natural gas co-firing in 2030 to convert to the natural-gas fired subcategory prior to the proposed date of January 1, 2040, instead of ceasing operation.

Other industry commenters suggested that to be a natural gas-fired steam generating unit, a source could either meet the heat input requirements during the 3 years prior to the compliance date *or* (emphasis added) no longer retain the capability to fire coal after December 31, 2029. Those commenters noted that, as proposed, a source that had planned to convert to 100 percent natural gas-firing would essentially have to do so prior to January 1, 2027, to meet the proposed heat input-based definition, in addition to removing the capability to fire coal by the compliance date.

[273] Duke Edwardsport DOE FEED Study Fact Sheet. *https://www.energy.gov/sites/default/files/2024-01/OCED_CCFEEDs_AwardeeFactSheet_Duke_1.5.2024.pdf.*

[274] For additional details on pre-combustion CO_2 capture, please see the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

Response: Although full natural gas conversions are not a measure that the EPA considered as a potential BSER, the emission guidelines do not prohibit such conversions should a state elect to require or accommodate them. As noted above, the EPA recognizes that many steam EGUs that formerly utilized coal as a primary fuel have fully or partially converted to natural gas, and that additional steam EGUs may elect to do so during the implementation period for these emission guidelines. However, these emission guidelines place reasonable constraints on the timing of such a conversion in situations where a source seeks to be regulated as a natural gas-fired steam EGU rather than as a coal-fired steam EGU. The EPA believes that such constraints are necessary in order to avoid creating a perverse incentive for EGUs to defer conversions in a way that could undermine the emission reduction purpose of the rule. Therefore, the EPA disagrees with those commenters that suggest the EPA should, in general, allow EGUs to be regulated as natural gas-fired steam EGUs when they undertake such conversions past January 1, 2030.

However, the EPA acknowledges that the proposed subcategorization would have essentially required a unit to convert to natural gas by January 1, 2027 in order to be regulated as a natural gas-fired steam EGU. The EPA is finalizing fuel type subcategorization based on the state of the source on the compliance date of January 1, 2030, and during any period thereafter, as detailed in section VII.B of this preamble. Should a source not be able to fully convert to natural gas by this date, it would be treated as a coal-fired steam generating EGU; however, the state may be able to use the RULOF provisions, as discussed in section X.C.2 of this preamble, to particularize a standard of performance for the unit. Note that if a state relies on operating conditions within the control of the source as the basis of providing a less stringent standard of performance or longer compliance schedule, it must include those operating conditions as an enforceable requirement in the state plan. 40 CFR 60.24a(g).

C. Rationale for the BSER for Coal-Fired Steam Generating Units

This section of the preamble describes the rationale for the final BSERs for existing coal-fired steam generating units based on the criteria described in section V.C of this preamble.

At proposal, the EPA evaluated two primary control technologies as potentially representing the BSER for existing coal-fired steam generating units: CCS and natural gas co-firing. For sources operating in the long-term, the EPA proposed CCS with 90 percent capture as BSER. For sources operating in the medium-term (*i.e.,* those demonstrating that they plan to permanently cease operation by January 1, 2040), the EPA proposed 40 percent natural gas co-firing as BSER. For imminent-term and near-term sources ceasing operation earlier, the EPA proposed BSERs of routine methods of operation and maintenance.

The EPA is finalizing CCS with 90 percent capture as BSER for coal-fired steam generating units because CCS can achieve a substantial amount of emission reductions and satisfies the other BSER criteria. CCS has been adequately demonstrated and results in by far the largest emissions reductions of the available control technologies. As noted below, the EPA has also determined that the compliance date for CCS is January 1, 2032. CCS, however, entails significant up-front capital expenditures that are amortized over a period of years. The EPA evaluated the cost for different amortization periods, and the EPA has concluded that CCS is cost-reasonable for units that operate past January 1, 2039. As noted in section IV.D.3.b of this preamble, about half (87 GW out of 181 GW) of all coal-fired capacity currently in existence has announced plans to permanently cease operations by January 1, 2039, and additional sources are likely to do so because they will be older than the age at which sources generally have permanently ceased operations since 2000. The EPA has determined that the remaining sources that may operate after January 1, 2039, can, on average, install CCS at a cost that is consistent with the EPA's metrics for cost reasonableness, accounting for an amortization period for the capital costs of more than 7 years, as detailed in section VII.C.1.a.ii of this preamble. If a particular source has costs of CCS that are fundamentally different from those amounts, the state may consider it to be a candidate for a different control requirement under the RULOF provision, as detailed in section X.C.2 of this preamble. For the group of sources that permanently cease operation before January 1, 2039, the EPA has concluded that CCS would in general be of higher cost, and therefore is finalizing a subcategory for these units, termed medium-term units, and finalizing 40 percent natural gas co-firing on a heat input basis as the BSER.

These final subcategories and BSERs are largely consistent with the proposal, which included a long-term subcategory for sources that did not plan to permanently cease operations by January 1, 2040, with 90 percent capture CCS as the BSER; and a medium-term subcategory for sources that permanently cease operations by that date and were not in any of the other proposed subcategories, discussed next, with 40 percent co-firing as the BSER. For both subcategories, the compliance date was January 1, 2030. The EPA also proposed an imminent-term subcategory, for sources that planned to permanently cease operations by January 1, 2032; and a near-term subcategory, for sources that planned to permanently case operations by January 1, 2035, and that limited their annual capacity utilization to 20 percent. The EPA proposed a BSER of routine methods of operation and maintenance for these two subcategories.

The EPA is not finalizing these imminent-term and near-term subcategories. In addition, after considering the comments, the EPA acknowledges that some additional time from what was proposed may be beneficial for the planning and installation of CCS. Therefore, the EPA is finalizing a January 1, 2032, compliance date for long-term existing coal-fired steam generating units. As noted above, the EPA's analysis of the costs of CCS also indicates that CCS is cost-reasonable with a minimum amortization period of seven years; as a result, the final emission guidelines would apply a CCS-based standard only to those units that plan to operate for at least seven years after the compliance deadline (*i.e.,* units that plan to remain in operation after January 1, 2039). For medium-term sources subject to a natural gas co-firing BSER, the EPA is finalizing a January 1, 2030, compliance date because the EPA has concluded that this provides a reasonable amount of time to begin co-firing, a technology that entails substantially less up-front infrastructure and, relatedly, capital expenditure than CCS.

1. Long-Term Coal-Fired Steam Generating Units

The EPA is finalizing CCS with 90 percent capture of CO_2 at the stack as BSER for long-term coal-fired steam generating units. Coal-fired steam generating units are the largest stationary source of CO_2 in the United States. Coal-fired steam generating units have higher emission rates than other generating technologies, about twice the emission rate of a natural gas combined cycle unit. Typically, even newer, more efficient coal-fired steam generating units emit over 1,800 lb CO_2/MWh-gross, while many existing coal-fired steam generating units have emission rates of 2,200 lb CO_2/MWh-gross or higher. As noted in section IV.B of this

preamble, coal-fired sources emitted 909 MMT CO_2e in 2021, 59 percent of the GHG emissions from the power sector and 14 percent of the total U.S. GHG emissions—contributing more to U.S. GHG emissions than any other sector, aside from transportation road sources.[275] Furthermore, considering the sources in the long-term subcategory will operate longer than sources with shorter operating horizons, long-term coal-fired units have the potential to emit more total CO_2.

CCS is a control technology that can be applied at the stack of a steam generating unit, achieves substantial reductions in emissions and can capture and permanently sequester more than 90 percent of CO_2 emitted by coal-fired steam generating units. The technology is adequately demonstrated, given that it has been operated at scale and is widely applicable to these sources, and there are vast sequestration opportunities across the continental U.S. Additionally, the costs for CCS are reasonable, in light of recent technology cost declines and policies including the tax credit under IRC section 45Q. Moreover, the non-air quality health and environmental impacts of CCS can be mitigated and the energy requirements of CCS are not unreasonably adverse. The EPA's weighing of these factors together provides the basis for finalizing CCS as BSER for these sources. In addition, this BSER determination aligns with the caselaw, discussed in section V.C.2.h of the preamble, stating that CAA section 111 encourages continued advancement in pollution control technology.

At proposal, the EPA also evaluated natural gas co-firing at 40 percent of heat input as a potential BSER for long-term coal-fired steam generating units. While the unit level emission rate reductions of 16 percent achieved by 40 percent natural gas co-firing are appreciable, those reductions are substantially less than CCS with 90 percent capture of CO_2. Therefore, because CCS achieves more reductions at the unit level and is cost-reasonable, the EPA is not finalizing natural gas co-firing as the BSER for these units. Further, the EPA is not finalizing partial-CCS at lower capture rates (*e.g.,* 30 percent) because it achieves substantially fewer unit-level reductions at greater cost, and because CCS at 90 percent is achievable. Notably, the IRC section 45Q tax credit may not be available to defray the costs of partial CCS and the emission reductions would be limited. And the EPA is not finalizing HRI as the BSER for these units because of the limited reductions and potential rebound effect.

a. Rationale for CCS as the BSER for Long-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA explains the rationale for CCS as the BSER for existing long-term coal-fired steam generating units. This section discusses the aspects of CCS that are relevant for existing coal-fired steam generating units and, in particular, long-term units. As noted in section VIII.F.4.c.iv of this preamble, much of this discussion is also relevant for the EPA's determination that CCS is the BSER for new base load combustion turbines.

In general, CCS has three major components: CO_2 capture, transportation, and sequestration/storage. Detailed descriptions of these components are provided in section VII.C.1.a.i of this preamble. As an overview, post-combustion capture processes remove CO_2 from the exhaust gas of a combustion system, such as a utility boiler or combustion turbine. This technology is referred to as ''post-combustion capture'' because CO_2 is a product of the combustion of the primary fuel and the capture takes place after the combustion of that fuel. The exhaust gases from most combustion processes are at atmospheric pressure, contain somewhat dilute concentrations of CO_2, and are moved through the flue gas duct system by fans. To separate the CO_2 contained in the flue gas, most current post-combustion capture systems utilize liquid solvents—commonly amine-based solvents—in CO_2 scrubber systems using chemical absorption (or chemisorption).[276] In a chemisorption-based separation process, the flue gas is processed through the CO_2 scrubber and the CO_2 is absorbed by the liquid solvent. The CO_2-rich solvent is then regenerated by heating the solvent to release the captured CO_2.

The high purity CO_2 is then compressed and transported, generally through pipelines, to a site for geologic sequestration (*i.e.,* the long-term containment of CO_2 in subsurface geologic formations). Pipelines are subject to Federal safety regulations administered by PHMSA. Furthermore, sequestration sites are widely available across the nation, and the EPA has developed a comprehensive regulatory structure to oversee geologic sequestration projects and assure their safety and effectiveness.[277]

i. Adequately Demonstrated

In this section of the preamble, the EPA explains the rationale for finalizing its determination that 90 percent capture applied to long-term coal-fired steam generating units is adequately demonstrated. In this section, the EPA first describes how simultaneous operation of all components of CCS functioning in concert with one another has been demonstrated, including a commercial scale application on a coal-fired steam generating unit. The demonstration of the individual components of CO_2 capture, transport, and sequestration further support that CCS is adequately demonstrated. The EPA describes how demonstrations of CO_2 capture support that 90 percent capture rates are adequately demonstrated. The EPA further describes how transport and geologic sequestration are adequately demonstrated, including the feasibility of transport infrastructure and the broad availability of geologic sequestration reservoirs in the U.S.

(A) Simultaneous Demonstration of CO_2 Capture, Transport, and Sequestration

The EPA proposed that CCS was adequately demonstrated for applications on combustion turbines and existing coal-fired steam generating units.

On reviewing the available information, all components of CCS—CO_2 capture, CO_2 transport, and CO_2 sequestration—have been demonstrated concurrently, with each component operating simultaneously and in concert with the other components.

(1) Industrial Applications of CCS

Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s [278] and has been used in a variety of industrial applications for decades. For example, since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant at Searles Valley Minerals (Trona,

[275] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2021. U.S. Greenhouse Gas Emissions by Inventory Sector, 2021. https://cfpub.epa.gov/ghgdata/inventoryexplorer/index.html#iallsectors/allsectors/allgas/inventsect/current.*

[276] Other technologies may be used to capture CO_2, as described in the final TSDs, *GHG Mitigation Measures for Steam Generating Units* and the *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* available in the rulemaking docket.

[277] 80 FR 64549 (October 23, 2015).

[278] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

California).[279] Furthermore, thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[280] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with EOR.[281] There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under construction or in advanced stages of development.[282] This broad application of CCS demonstrates that the components of CCS have been successfully operated simultaneously. The Shute Creek Facility has a capture capacity of 7 million metric tons per year and has been in operation since 1986.[283] The facility uses a solvent-based process to remove CO_2 from natural gas, and the captured CO_2 is stored in association with EOR. Another example of CCS in industrial applications is the Great Plains Synfuels Plant has a capture capacity of 3 million metric tons per year and has been in operation since 2000.[284] [285] The Great Plains Synfuels Plant (Beulah, North Dakota) uses a solvent-based process to remove CO_2 from lignite-derived syngas, the CO_2 is transported by the Souris Valley pipeline, and stored underground in association with EOR in the Weyburn and Midale Oil Units in Saskatchewan, Canada. Over 39 million metric tons of CO_2 has been captured since 2000.

(2) Various CO_2 capture methods are used in industrial applications and are tailored to the flue gas conditions of a particular industry (see the TSD *GHG Mitigation Measures for Steam Generating Units* for details). Of those capture technologies, amine solvent-based capture has been demonstrated for removal of CO_2 from the post-combustion flue gas of fossil fuel-fired EGUs. The Quest CO_2 capture facility in Alberta, Canada, uses amine-based CO_2 capture retrofitted to three existing steam methane reformers at the Scotford Upgrader facility (operated by Shell Canada Energy) to capture and sequester approximately 80 percent of the CO_2 in the produced syngas.[286] Amine-solvents are also applied for post-combustion capture from fossil fuel fired EGUs. The Quest facility has been operating since 2015 and captures approximately 1 million metric tons of CO_2 per year.

Applications of CCS at Coal-Fired Steam Generating Units

For electricity generation applications, this includes operation of CCS at Boundary Dam Unit 3 in Saskatchewan, Canada. CCS at Boundary Dam Unit 3 includes capture of the CO_2 from the flue-gas of the fossil fuel-fired EGU, compression of the CO_2 onsite and transport via pipeline offsite, and storage of the captured CO_2 underground. Storage of the CO_2 captured at Boundary Dam primarily occurs via EOR. Moreover, CO_2 captured from Boundary Dam Unit 3 is also stored in a deep saline aquifer at the Aquistore Deep Saline CO_2 Storage Project, which has permanently stored over 550,000 tons of CO_2 to date.[287] Other demonstrations of CCS include the 240 MWe Petra Nova CCS project at the subbituminous coal-fired W.A. Parish plant in Texas, which, because it was EPAct05-assisted, we cite as useful in section VII.C.1.a.i(B)(2) of this preamble, but not essential, corroboration. See section VII.C.1.a.i(H)(1) for a detailed description of how the EPA considers information from EPAct05-assisted projects.

Commenters stated that that all constituent components of CCS—carbon capture, transportation, and sequestration—have not been adequately demonstrated in integrated, simultaneous operation. We disagree with this comment. The record described in the preceding shows that all components have been demonstrated simultaneously. Even if the record only included demonstration of the individual components of CCS, the EPA would still determine that CCS is adequately demonstrated as it would be reasonable on a technical basis that the individual components are capable of functioning together—they have been engineered and designed to do so, and the record for the demonstration of the individual components is based on decades of direct data and experience.

(B) CO_2 Capture Technology at Coal-Fired Steam Generating Units

The EPA is finalizing the determination that the CO_2 capture component of CCS has been adequately demonstrated at a capture efficiency of 90 percent, is technically feasible, and is achievable over long periods (*e.g.,* a year) for the reasons summarized here and detailed in the following subsections of this preamble. This determination is based, in part, on the demonstration of the technology at existing coal-fired steam generating units, including the commercial-scale installation at Boundary Dam Unit 3. The application of CCS at Boundary Dam follows decades of development of CO_2 capture for coal-fired steam generating units, as well as numerous smaller-scale demonstrations that have successfully implemented this technology. Review of the available information has also identified specific, currently available, minor technological improvements that can be applied today to better the performance of new capture plant retrofits, and which can assure that the capture plants achieve 90 percent capture. The EPA's determination that 90 percent capture of CO_2 is adequately demonstrated is further corroborated by EPAct05-assisted projects, including the Petra Nova project.

Moreover, several CCS retrofit projects on coal-fired steam generating units are in progress that apply the lessons from the prior projects and use solvents that achieve higher capture rates. Technology providers that supply those solvents and the associated process technologies have made statements concluding that the technology is commercially proven and available today and have further stated that those solvents achieve capture rates of 95 percent or greater. Technology providers have decades of experience and have done the work to responsibly scale up the technology over that time across a range of flue gas compositions. Taking all of those factors into consideration, and accounting for the operation and flue gas conditions of the affected sources, solvent-based capture will consistently achieve capture rates of 90 percent or greater for the fleet of long-term coal-fired steam generating units.

Various technologies may be used to capture CO_2, the details of which are described generally in section IV.C.1 of this preamble and in more detail in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* which is

[279] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[280] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[281] GHGRP US EPA. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[282] Carbon Capture and Storage in the United States. CBO. December 13, 2023. *https://www.cbo.gov/publication/59345.*

[283] *Id.*

[284] *https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/great-plains.*

[285] *https://co2re.co/FacilityData.*

[286] Quest Carbon Capture and Storage Project Annual Summary Report, Alberta Department of Energy: 2021. *https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2021.*

[287] Aquistore Project. *https://ptrc.ca/media/whats-new/aquistore-co2-storage-project-reached-+500000-tonnes-stored.*

available in the rulemaking docket.[288] For post-combustion capture, these technologies include solvent-based methods (*e.g.,* amines, chilled ammonia), solid sorbent-based methods, membrane filtration, pressure-swing adsorption, and cryogenic methods.[289] Lastly, oxy-combustion uses a purified oxygen stream from an air separation unit (often diluted with recycled CO_2 to control the flame temperature) to combust the fuel and produce a higher concentration of CO_2 in the flue gas, as opposed to combustion with oxygen in air which contains 80 percent nitrogen. The CO_2 can then be separated by the aforementioned CO_2 capture methods. Of the available capture technologies, solvent-based processes have been the most widely demonstrated at commercial scale for post-combustion capture and are applicable to use with either combustion turbines or steam generating units.

The EPA's identification of CCS with 90 percent capture as the BSER is premised, in part, on an amine solvent-based CO_2 system. Amine solvents used for carbon capture are typically proprietary, although non-proprietary solvents (*e.g.,* monoethanolamine, MEA) may be used. Carbon capture occurs by reactive absorption of the CO_2 from the flue gas into the amine solution in an absorption column. The amine reacts with the CO_2 but will also react with impurities in the flue gas, including SO_2. PM will also affect the capture system. Adequate removal of SO_2 and PM prior to the CO_2 capture system is therefore necessary. After pretreatment of the flue gas with conventional SO_2 and PM controls, the flue gas goes through a quencher to cool the flue gas and remove further impurities before the CO_2 absorption column. After absorption, the CO_2-rich amine solution passes to the solvent regeneration column, while the treated gas passes through a water and/or acid wash column to limit emission of amines or other byproducts. In the solvent regeneration column, the solution is heated (using steam) to release the absorbed CO_2. The released CO_2 is then compressed and transported offsite, usually by pipeline. The amine solution from the regenerating column is then cooled, a portion of the lean solvent is treated in a solvent reclaiming process to mitigate degradation of the solvent, and the lean solvent streams are recombined and sent back to the absorption column.

(1) Capture Demonstrations at Coal-Fired Steam Generating Units

(a) SaskPower's Boundary Dam Unit 3

SaskPower's Boundary Dam Unit 3, a 110 MW lignite-fired unit in Saskatchewan, Canada, was designed to achieve CO_2 capture rates of 90 percent using an amine-based post-combustion capture system retrofitted to the existing steam generating unit. The capture plant, which began operation in 2014, is the first full-scale CO_2 capture system retrofit on an existing coal-fired power plant. It uses the amine-based Shell CANSOLV® process, which includes an amine-based SO_2 scrubbing process and a separate amine-based CO_2 capture process, with integrated heat and power from the steam generating unit.[290]

After undergoing maintenance and design improvements in September and October of 2015 to address technical and mechanical challenges faced in its first year of operation, Boundary Dam Unit 3 completed a 72-hour test of its design capture rate (3,240 metric tons/day), and captured 9,695 metric tons of CO_2 or 99.7 percent of the design capacity (approximately 89.7 percent capture) with a peak rate of 3,341 metric tons/day.[291] However, the capture plant has not consistently operated at this total capture efficiency. In general, the capture plant ran less than 100 percent of the flue gas through the capture equipment and the coal-fired steam generating unit also operates when the capture plant is offline for maintenance. As a result, although the capture plant has consistently achieved 90 percent capture rates of the CO_2 in the processed slipstream, the amount of CO_2 captured was less than 90 percent of the total amount of CO_2 in the flue gas of the steam generating unit. Some of the reasons for this operation were due to the economic incentives and regulatory requirements of the project, while other reasons were due to technical challenges. The EPA has reviewed the record of CO_2 capture at Boundary Dam Unit 3. While Boundary Dam is in Canada and therefore not subject to this action, these technical challenges have been sufficiently overcome or are actively mitigated so that Boundary Dam has more recently been capable of achieving capture rates of 83 percent when the capture plant is online.[292] Furthermore, the improvements already employed and identified at Boundary Dam can be readily applied during the initial construction of a new CO_2 capture plant today.

The CO_2 captured at Boundary Dam is mostly used for EOR and CO_2 is also stored geologically in a deep saline reservoir at the Aquistore site.[293] The amount of flue gas captured is based in part on economic reasons (*i.e.,* to meet related contract requirements). The incentives for CO_2 capture at Boundary Dam beyond revenue from EOR have been limited to date, and there have been limited regulatory requirements for CO_2 capture at the facility. As a result, a portion (about 25 percent on average) of the flue gas bypasses the capture plant and is emitted untreated. However, because of increasing requirements to capture CO_2 in Canada, Boundary Dam Unit 3 has more recently pursued further process optimization.

Total capture efficiencies at the plant have also been affected by technical issues, particularly with the SO_2 removal system that is upstream of the CO_2 capture system. Operation of the SO_2 removal system affects downstream CO_2 capture and the amount of flue gas that can be processed. Specifically, fly ash (PM) in the flue gas at Boundary Dam Unit 3 contributed to fouling of SO_2 system components, particularly in the SO_2 reboiler and the demisters of the SO_2 absorber column. Buildup of scale in the SO_2 reboiler limited heat transfer and regeneration of the SO_2 scrubbing amine, and high pressure drop affected the flowrate of the SO_2 lean-solvent back to the SO_2 absorber. Likewise, fouling of the demisters in the SO_2 absorber column caused high pressure drop and restricted the flow of flue gas through the system, limiting the amount of flue gas that could be processed by the downstream CO_2 capture system. To address these technical issues, additional wash systems were added, including ''demister wash systems, a pre-scrubber flue gas inlet curtain spray wash system, flue gas cooler throat sprays, and a booster fan wash system.'' [294]

[288] Technologies to capture CO_2 are also discussed in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines.*

[289] For pre-combustion capture (as is applicable to an IGCC unit), syngas produced by gasification passes through a water-gas shift catalyst to produce a gas stream with a higher concentration of hydrogen and CO_2. The higher CO_2 concentration relative to conventional combustion flue gas reduces the demands (power, heating, and cooling) of the subsequent CO_2 capture process (*e.g.,* solid sorbent-based or solvent-based capture); the treated hydrogen can then be combusted in the unit.

[290] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820191.*

[291] SaskPower Annual Report (2015–16). *https://www.saskpower.com/about-us/Our-Company/~/link.aspx?_id=29E795C8C20D48398EAB5E3273C256AD&_z=z.*

[293] Aquistore. *https://ptrc.ca/aquistore.*

[294] *Id.*

Such issues will definitively not occur in a different type of SO_2 removal system (*e.g.,* wet lime scrubber flue gas desulfurization, wet-FGD). SO_2 scrubbers have been successfully operated for decades across a large number of U.S. coal-fired sources. Of the coal-fired sources with planned operation after 2039, 60 percent have wet FGD and 23 percent have a dry FGD. In section VII.C.1.a.ii of this preamble, the EPA accounts for the cost of adding a wet-FGD for those sources that do not have an FGD.

To further mitigate fouling due to fly ash, the PM controls (electrostatic precipitators) at Boundary Dam Unit 3 were upgraded in 2015/2016 by adding switch integrated rectifiers. Of the coal-fired sources with planned operation after 2039, 31 percent have baghouses and 67 percent have electrostatic precipitators. Sources with baghouses have greater or more consistent degrees of emission control, and wet FGD also provides additional PM control.

Fouling at Boundary Dam Unit 3 also affected the heat exchangers in both the SO_2 removal system and the CO_2 capture system. Additional redundancies and isolations to those key components were added in 2017 to allow for online maintenance. Damage to the capture plant's CO_2 compressor resulted in an unplanned outage in 2021, and the issue was corrected.[295] The facility reported 98.3 percent capture system availability in the third quarter of 2023.[296]

Regular maintenance further mitigates fouling in the SO_2 and CO_2 absorbers, and other challenges (*e.g.,* foaming, biological fouling) typical of gas-liquid absorbers can be mitigated by standard procedures. According to the 2022 paper co-authored by the International CCS Knowledge Centre and SaskPower, ''[a] number of initiatives are ongoing or planned with the goal of eliminating flue gas bypass as follows: Since 2016, online cleaning of demisters has been effective at controlling demister pressure; Chemical cleans and replacement of fouled packing in the absorber towers to reduce pressure losses; Optimization of antifoam injection and other aspects of amine health, to minimize foaming potential; [and] Optimization of Liquid-to-Gas (L/G) ratio in the absorber and other process parameters,'' as well as other optimization procedures.[297] While foaming is mitigated by an antifoam injection regimen, the EPA further notes that the extent of foaming that could occur may be specific to the chemistry of the solvent and the source's flue gas conditions—foaming was not reported for MHI's KS–1 solvent when treating bituminous coal post-combustion flue gas at Petra Nova. Lastly, while biological fouling in the CO_2 absorber wash water and the SO_2 absorber caustic polisher has been observed, ''the current mitigation plan is to perform chemical shocking to remove this particular buildup.'' [298]

Based on the experiences of Boundary Dam Unit 3, key improvements can be implemented in future CCS deployments during initial design and construction. Improvements to PM and SO_2 controls can be made prior to operation of the CO_2 capture system. Where fly ash is present in the flue gas, wash systems can be installed to limit associated fouling. Additional redundancies and isolations of key heat-exchangers can be made to allow for in-line cleaning during operation. Redundancy of key equipment (*e.g.,* utilizing two CO_2 compressor trains instead of one) will further improve operational availability. A feasibility study for the Shand power plant, which is also operated by SaskPower, includes many such design improvements, at an overall cost that was less than the cost for Boundary Dam.[299]

(b) Other Coal-Fired Demonstrations

Several other projects have successfully demonstrated the capture component of CCS at electricity generating plants and other industrial facilities, some of which were previously noted in the discussion in the 2015 NSPS.[300] Since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant (Trona, California).[301] Amine-based carbon capture has further been demonstrated at AES's Warrior Run (Cumberland, Maryland) and Shady Point (Panama, Oklahoma) coal-fired power plants, with the captured CO_2 being sold for use in the food processing industry.[302] At the 180 MW bituminous coal-fired Warrior Run plant, approximately 10 percent of the plant's CO_2 emissions (about 110,000 metric tons of CO_2 per year) has been captured since 2000 and sold to the food and beverage industry. AES's 320 MW Shady Point plant fires subbituminous and bituminous coal, and captured CO_2 from an approximate 5 percent slipstream (about 66,000 metric tons of CO_2 per year) from 2001 through around 2019.[303] These facilities, which have operated for multiple years, clearly show the technical feasibility of post-combustion carbon capture.

(2) EPAct05-Assisted CO_2 Capture Projects at Coal-Fired Steam Generating Units [304]

(a) Petra Nova

Petra Nova is a 240 MW-equivalent capture facility that is the first at-scale application of carbon capture at a coal-fired power plant in the U.S. The system is located at the subbituminous coal-

[295] S&P Global Market Intelligence (January 6, 2022). Only still-operating carbon capture project battled technical issues in 2021. *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/only-still-operating-carbon-capture-project-battled-technical-issues-in-2021-68302671.*

[296] SaskPower (October 18, 2022). *BD3 Status Update: Q3 2023. https://www.saskpower.com/about-us/Our-Company/Blog/2023/BD3-Status-Update-Q3-2023.*

[297] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[298] Pradoo, P., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286503.*

[299] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

[300] 80 FR 64548–54 (October 23, 2015).

[301] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[302] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[303] Shady Point Plant (River Valley) was sold to Oklahoma Gas and Electric in 2019. *https://www.oklahoman.com/story/business/columns/2019/05/23/oklahoma-gas-and-electric-acquires-aes-shady-point-after-federal-approval/60454346007/.*

[304] In the 2015 NSPS, the EPA provided a legal interpretation of the constraints on how the EPA could rely on EPAct05-assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111. Under that legal interpretation, ''these provisions [in the EPAct05] . . . preclude the EPA from relying solely on the experience of facilities that received [EPAct05] assistance, but [do] not . . . preclude the EPA from relying on the experience of such facilities in conjunction with other information.'' As part of the rulemaking action here, the EPA incorporates the legal interpretation and discussion of these EPAct05 provisions with respect the appropriateness of considering facilities that received EPAct05 assistance in determining whether CCS is adequately demonstrated, as found in the 2015 NSPS, 80 FR 64509, 64541–43 (October 23, 2015), and the supporting response to comments, EPA–HQ–OAR–2013–0495–11861 at pgs.113–134.

fired W.A. Parish Generating Station in Thompsons, Texas, and began operation in 2017, successfully capturing and sequestering CO_2 for several years. The system was put into reserve shutdown (*i.e.,* idled) in May 2020, citing the poor economics of utilizing captured CO_2 for EOR at that time. On September 13, 2023, JX Nippon announced that the carbon capture facility at Petra Nova had been restarted.[305] A final report from the National Energy Technology Laboratory (NETL) details the success of the project and what was learned from this first-of-a-kind demonstration at scale.[306] The project used Mitsubishi Heavy Industry's proprietary KM–CDR Process®, a process that is similar to an amine-based solvent process but that uses a proprietary solvent. During its operation, the project successfully captured 92.4 percent of the CO_2 from the slip stream of flue gas processed with 99.08 percent of the captured CO_2 sequestered by EOR.

The amount of flue gas treated at Petra Nova was consistent with a 240 MW size coal-fired steam EGU. The properties of the flue gas—composition, temperature, pressure, density, flowrate, *etc.*—are the same as would occur for a similarly sized coal-firing unit. Therefore, Petra Nova corroborates that the capture equipment—including the CO_2 absorption column, solvent regeneration column, balance of plant equipment, and the solvent itself—work at commercial scale and can achieve capture rates of 90 percent.

The Petra Nova project did experience periodic outages that were unrelated to the CO_2 capture facility and do not implicate the basis for the EPA's BSER determination.[307] These include outages at either the coal-fired steam generating unit (W.A. Parish Unit 8) or the auxiliary combined cycle facility, extreme weather events (Hurricane Harvey), and the operation of the EOR site and downstream oil recovery and processing. Outages at the coal-fired steam generating unit itself do not compromise the reliability of the CO_2 capture plant or the plant's ability to achieve a standard of performance based on CCS, as there would be no CO_2 to capture. Outages at the auxiliary combined cycle facility are also not relevant to the EPA's BSER determination, because the final BSER is not premised on the CO_2 capture plant using an auxiliary combined cycle plant for steam and power. Rather, the final BSER assumes the steam and power come directly from the associated steam generating unit. Extreme weather events can affect the operation of any facility. Furthermore, the BSER is not premised on EOR, and it is not dependent on downstream oil recovery or processing. Outages attributable to the CO_2 capture facility were 41 days in 2017, 34 days in 2018, and 29 days in 2019—outages decreased year-on-year and were on average less than 10 percent of the year. Planned and unplanned outages are normal for industrial processes, including steam generating units.

Petra Nova experienced some technical challenges that were addressed during its first 3 years of operation.[308] One of these issues was leaks from heat exchangers due to the properties of the gasket materials—replacement of the gaskets addressed the issue. Another issue was vibration of the flue gas blower due to build-up of slurry and solids carryover. W.A. Parish Unit 8 uses a wet limestone FGD scrubber to remove SO_2, and the flue gas connection to the capture plant is located at the bottom of the duct running from the wet-FGD to the original stack. A diversion wall and collection drains were installed to mitigate solids and slurry carryover. Regular maintenance is required to clean affected components and reduce the amount of slurry carryover to the quencher. Solids and slurry carryover also resulted in calcium scale buildup on the flue gas blower. Although calcium concentrations were observed to increase in the solvent, impacts of calcium on the quencher and capture plant chemistry were not observed. Some scaling may have been occurring in the cooling section of the quencher and would have been addressed during a planned outage in 2020. Another issue encountered was scaling related to the CO_2 compressor intercoolers, compressor dehydration system, and an associated heat exchanger. The issue was determined to be due to a material incompatibility of the CO_2 compressor intercooler, and the components were replaced during a 2018 planned outage. To mitigate the scaling prior to the replacement of those components, the compressor drain was also rerouted to the reclaimer and a backup filtering system was also installed and used, both of which proved to be effective. Some decrease in performance was also observed in heat exchangers. The presence of cooling tower fill (a solid medium used to increase surface area in cooling towers) in the cooling water system exchangers may have impacted performance. It is also possible that there could have been some fouling in heat exchangers. Fill was planned to be removed and fouling checked for during regular maintenance. Petra Nova did not observe fouling of the CO_2 absorber packing or high pressure drops across the CO_2 absorber bed, and Petra Nova also did not report any foaming of the solvent. Even with the challenges that were faced, Petra Nova was never restricted in reaching its maximum capture rate of 5,200 tons of CO_2 per day, a scale that was substantially greater than Boundary Dam Unit 3 (approximately 3,600 tons of CO_2 per day).

(b) Plant Barry

Plant Barry, a bituminous coal-fired steam generating unit in Mobile, Alabama, began using the KM–CDR Process® in 2011 for a fully integrated 25 MWe CCS project with a capture rate of 90 percent.[309] The CCS project at Plant Barry captured approximately 165,000 tons of CO_2 annually, which was then transported via pipeline and sequestered underground in geologic formations.[310]

(c) Project Tundra

Project Tundra is a carbon capture project in North Dakota at the Milton R. Young Station lignite coal-fired power plant. Project Tundra will capture up to 4 million metric tons of CO_2 per year for permanent geologic storage. One planned storage site is collocated with the power plant and is already fully permitted, while permitting for a second nearby storage site is in progress.[311] An air permit for the capture facility has also been issued by North Dakota Department of Environmental Quality. The project is designed to capture CO_2 at a rate of about 95 percent of the treated flue gas.[312] The capture plant will treat the flue gas from the 455 MW Unit 2 and additional flue gas from the 250 MW Unit 1, and will treat an equivalent capacity of 530 MW.[313] The project began a final FEED study in February 2023 with planned completion

[305] JX Nippon Oil & Gas Exploration Corporation. *Restart of the large-scale Petra Nova Carbon Capture Facility in the U.S.* (September 2023). *https://www.nex.jx-group.co.jp/english/newsrelease/upload_files/20230913EN.pdf.*

[306] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[307] *Id.*

[308] *Id.*

[309] U.S. Department of Energy (DOE). National Energy Technology Laboratory (NETL). *https://www.netl.doe.gov/node/1741.*

[310] 80 FR 64552 (October 23, 2015).

[311] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[312] See Document ID No. EPA–HQ–OAR–2023–0072–0632.

[313] *Id.*

in April 2024,[314] and, prior to selection by DOE for funding award negotiation, the project was scheduled to begin construction in 2024.[315] The project will use MHI's KS–21 solvent and the Advanced KM–CDR process. The MHI solvent KS–1 and an advanced MHI solvent (likely KS–21) were previously tested on the lignite post-combustion flue gas from the Milton R. Young Station.[316] To provide additional conditioning of the flue gas, the project is utilizing a wet electrostatic precipitator (WESP). A draft Environmental Assessment summarizing the project and potential environmental impacts was released by DOE.[317] Finally, Project Tundra was selected for award negotiation for funding from DOE.[318]

That this project has funding through the Bipartisan Infrastructure Law, and that this funding is facilitated through DOE's Office of Clean Energy Demonstration's (OCED) Carbon Capture Demonstration Projects Program, does not detract from the adequate demonstration of CCS. Rather, the goal of that program is, ''to accelerate the implementation of integrated carbon capture and storage technologies and catalyze significant follow-on investments from the private sector to mitigate carbon emissions sources in industries across America.'' [319] For the commercial scale projects, the stated requirement of the funding opportunity announcement (FOA) is not that projects demonstrate CCS in general, but that they ''demonstrate significant improvements in the efficiency, effectiveness, cost, operational and environmental performance of existing carbon capture technologies.'' [320] This implies that the basic technology already exists and is already demonstrated. The FOA further notes that the technologies used by the projects receiving funding should be proven such that, ''the technologies funded can be readily replicated and deployed into commercial practice.'' [321] The EPA also notes that this and other on-going projects were announced well in advance of the FOA. Considering these factors, Project Tundra and other similarly funded projects are supportive of the determination that CCS is adequately demonstrated.

(d) Project Diamond Vault

Project Diamond Vault will capture up to 95 percent of CO_2 emissions from the 600 MW Madison Unit 3 at Brame Energy Center in Lena, Louisiana. Madison Unit 3 fires approximately 70 percent petroleum coke and 30 percent bituminous (Illinois Basin) coal in a circulating fluidized bed. The FEED study for the project is targeted for completion on September 9, 2024.[322] [323] Construction is planned to begin by the end of 2025 with commercial operation starting in 2028.[324] From the utility: ''Government Inflation Reduction Act (IRA) funding through 45Q tax credits makes the project financially viable. With these government tax credits, the company does not expect a rate increase as a result of this project.'' [325]

(e) Other Projects

Other projects have completed or are in the process of completing feasibility work or FEED studies, or are taking other steps towards installing CCS on coal-fired steam generating units. These projects are summarized in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket. In general, these projects target capture rates of 90 percent or above and provide evidence that sources are actively pursuing the installation of CCS.

(3) CO_2 Capture Technology Vendor Statements

CO_2 capture technology providers have issued statements supportive of the application of systems and solvents for CO_2 capture at fossil fuel-fired EGUs. These statements speak to the decades of experience that technology providers have and as noted below, vendors attest, and offer guarantees that 90 percent capture rates are achievable. Generally, while there are many CO_2 capture methods available, solvent-based CO_2 capture from post-combustion flue gas is particularly applicable to fossil fuel-fired EGUs. Solvent-based CO_2 capture systems are commercially available from technology providers including Shell, Mitsubishi Heavy Industries (MHI), Linde/BASF, Fluor and ION Clean Energy.

Technology providers have made statements asserting extensive experience in CO_2 capture and the commercial availability of CO_2 capture technologies. Solvent-based CO_2 capture was first patented in the 1930s.[326] Since then, commercial solvent-based capture systems have been developed that are focused on applications to post-combustion flue gas. Several technology providers have over 30 years of experience applying solvent-based CO_2 capture to the post-combustion flue gas of fossil fuel-fired EGUs. In general, technology providers describe the technologies for CO_2 capture from post-combustion flue gas as ''proven'' or ''commercially available'' or ''commercially proven'' or ''available now'' and describe their experience with CO_2 capture from post-combustion flue gas as ''extensive.'' CO_2 capture rates of 90 percent or higher from post-combustion flue gas have been proven by CO_2 capture technology providers using several commercially available solvents. Many of the available solvent technologies have over 50,000 hours of operation, equivalent to over 5 years of operation.

Shell has decades of experience in CO_2 capture systems. Shell notes that ''[c]apturing and safely storing carbon is an option that's available now.'' [327] Shell has developed the CANSOLV® CO_2 capture system for CO_2 capture from post-combustion flue gas, a regenerable amine that the company claims has multiple advantages including ''low parasitic energy consumption, fast kinetics and extremely low volatility.'' [328] Shell further notes, ''Moreover, the technology has been designed for

[314] ''An Overview of Minnkota's Carbon Capture Initiative—Project Tundra,'' 2023 LEC Annual Meeting, October 5, 2023.

[315] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[316] Laum, Jason. Subtask 2.4—Overcoming Barriers to the Implementation of Postcombustion Carbon Capture. *https://www.osti.gov/biblio/1580659.*

[317] DOE–EA–2197 Draft Environmental Assessment, August 17, 2023. *https://www.energy.gov/nepa/listings/doeea-2197-documents-available-download.*

[318] Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

[319] DOE. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-program-front-end-engineering-design-feed-studies.*

[320] DE–FOA–0002962. *https://oced-exchange.energy.gov/FileContent.aspx?FileID=86c47d5d-835c-4343-86e8-2ba27d9dc119.*

[321] *Id.*

[322] Diamond Vault Carbon Capture FEED Study. *https://netl.doe.gov/sites/default/files/netl-file/23CM_PSCC31_Bordelon.pdf.*

[323] Note that while the FEED study is EPAct05-assisted, the capture plant is not.

[324] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[325] *Id.*

[326] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[327] Shell Global—Carbon Capture and Storage. *https://www.shell.com/energy-and-innovation/carbon-capture-and-storage.html.*

[328] Shell Global—CANSOLV® CO_2 Capture System. *https://www.shell.com/business-customers/catalysts-technologies/licensed-technologies/emissions-standards/tail-gas-treatment-unit/cansolv-co2.html.*

reliability through its highly flexible turn-up and turndown capacity.'' [329] The company has stated that ''Over 90% of the CO_2 in exhaust gases can be effectively and economically removed through the implementation of Shell's carbon capture technology.'' [330] Shell also notes, ''Systems can be guaranteed for bulk CO_2 removal of over 90%.'' [331]

MHI in collaboration with Kansai Electric Power Co., Inc. began developing a solvent-based capture process (the KM CDR Process™) using the KS–1™ solvent in 1990.[332] MHI describes the extensive experience of commercial application of the solvent, ''KS–1™—a solvent whose high reliability has been confirmed by a track record of deliveries to 15 commercial plants worldwide.'' [333] Notable applications of KS–1™ and the KM–CDR Process™ include applications at Plant Barry and Petra Nova. Previously, MHI has achieved capture rates of greater than 90 percent over long periods and at full scale at the Petra Nova project where the KS–1™ solvent was used.[334] MHI has further improved on the original process and solvent by making available the Advanced KM CDR Process™ using the KS–21™ solvent. From MHI, ''Commercialization of KS–21™ solvent was completed following demonstration testing in 2021 at the Technology Centre Mongstad in Norway, one of the world's largest carbon capture demonstration facilities.'' [335] MHI has achieved CO_2 capture rates of 95 to 98 percent using both the KS–1™ and KS–21™ solvent at the Technology Centre Mongstad (TCM).[336] Higher capture rates under modified conditions were also measured, ''In addition, in testing conducted under modified operating conditions, the KS–21™ solvent delivered an industry-leading carbon capture rate was 99.8% and demonstrated the successful recovery of CO_2 from flue gas of lower concentration than the CO_2 contained in the atmosphere.'' [337]

Linde engineering in partnership with BASF has made available BASF's OASE® blue amine solvent technology for post-combustion CO_2 capture. Linde notes their experience: ''We have longstanding experience in the design and construction of chemical wash processes, providing the necessary amine-based solvent systems and the CO_2 compression, drying and purification system.'' [338] Linde also notes that ''[t]he BASF OASE® process is used successfully in more than 400 plants worldwide to scrub natural, synthesis and other industrial gases.'' [339] The OASE® blue technology has been successfully piloted at RWE Power, Niederaussem, Germany (from 2009 through 2017; 55,000 operating hours) and the National Center for Carbon Capture in Wilsonville, Alabama (January 2015 through January 2016; 3,200 operating hours). Based on the demonstrated performance, Linde concludes that ''PCC plants combining Linde's engineering skills and BASF's OASE® blue solvent technology are now commercially available for a wide range of applications.'' [340] Linde and BASF have demonstrated capture rates over 90 percent and operating availability [341] rates of more than 97 percent during 55,000 hours of operation.

Fluor provides a solvent technology (Econamine FG Plus) and EPC services for CO_2 capture. Fluor describes their technology as ''proven,'' noting that, ''Proven technology. Fluor Econamine FG Plus technology is a propriety carbon capture solution with more than 30 licensed plants and more than 30 years of operation.'' [342] Fluor further notes, ''The technology builds on Fluor's more than 400 CO_2 removal units in natural gas and synthesis gas processing.'' [343] Fluor further states, ''Fluor is a global leader in CO_2 capture [. . .] with long-term commercial operating experience in CO_2 recovery from flue gas.'' On the status of Econamine FG Plus, Fluor notes that the ''[the] Technology [is] commercially proven on natural gas, coal, and fuel oil flue gases,'' and further note that ''[o]perating experience includes using steam reformers, gas turbines, gas engines, and coal/natural gas boilers.''

ION Clean Energy is a company focused on post-combustion carbon capture founded in 2008. ION's ICE–21 solvent has been used at NCCC and TCM Norway.[344] ION has achieved capture rates of 98 percent using the ICE–31 solvent.

(4) CCS User Statements on CCS

A number of the companies who have either completed large scale pilot projects or who are currently developing full scale projects have also indicated that CCS technology is currently a viable technology for large coal-fired power plants. In 2011, announcing a decision not to move forward with the first full scale commercial CCS installation of a carbon capture system on a coal plant, AEP did not cite any technology concerns, but rather indicated that ''it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place.'' [345] Enchant Energy, a company developing CCS for coal-fired power plants explained that its FEED study for the San Juan Generating Station, ''shows that the technical and business case for adding carbon capture to existing coal-fired power plants is strong.'' [346] Rainbow Energy, who is developing a carbon capture project at the Coal Creek Power Station in North Dakota explains, ''CCUS technology has been proven and is an economical option for a facility like Coal Creek Station. We see CCUS as the best option to manage CO_2 emissions at our facility.'' [347]

(5) State CCS Requirements

Several states encourage or even require sources to install CCS. These state requirements further indicate that CCS is well-established and effective. These state laws include the Illinois 2021 Climate and Equitable Jobs Act, which requires privately owned coal-

[329] Shell Catalysts & Technologies—Shell CANSOLV® CO_2 Capture System. *https://catalysts.shell.com/en/Cansolv-co2-fact-sheet.*

[330] *Id.*

[331] *Id.*

[332] Mitsubishi Heavy Industries—CO_2 Capture Technology—CO_2 Capture Process. *https://www.mhi.com/products/engineering/co2plants_process.html.*

[333] *Id.*

[334] Note: Petra Nova is an EPAct05-assisted project. W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[335] *Id.*

[336] Mitsubishi Heavy Industries, ''Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New KS–21™ Solvent for CO_2 Capture,'' *https://www.mhi.com/news/211019.html.*

[337] *Id.*

[338] Linde Engineering—Post Combustion Capture. *https://www.linde-engineering.com/en/process-plants/co2-plants/carbon-capture/post-combustion-capture/index.html.*

[339] Linde and BASF—Carbon capture storage and utilisation. *https://www.linde-engineering.com/en/images/Carbon-capture-storage-utilisation-Linde-BASF_tcm19-462558.pdf.*

[340] *Id.*

[341] Operating availability is the percent of time that the CO_2 capture equipment is available relative to its planned operation.

[342] Fluor—Comprehensive Solutions for Carbon Capture. *https://www.fluor.com/client-markets/energy/production/carbon-capture.*

[343] Fluor—Econamine FG Plus℠. *https://www.fluor.com/sitecollectiondocuments/qr/econamine-fg-plus-brochure.pdf.*

[344] ION Clean Energy—Company. *https://www.ioncleanenergy.com/company.*

[345] *https://www.aep.com/news/releases/read/1206/AEP-Places-Carbon-Capture-Commercialization-On-Hold-Citing-Uncertain-Status-Of-Climate-Policy-Weak-Economy.*

[346] Enchant Energy. What is Carbon Capture and Sequestration (CCS)? *https://enchantenergy.com/carbon-capture-technology/.*

[347] Rainbow Energy Center. Carbon Capture. *https://rainbowenergycenter.com/what-we-do/carbon-capture/.*

fired units to reduce emissions to zero by 2030 and requires publicly owned coal-fired units to reduce emissions to zero by 2045.[348] Illinois has also imposed CCS-based CO_2 emission standards on new coal-fired power plants since 2009 when the state adopted its Clean Coal Portfolio Standard law.[349] The statute required an initial capture rate of 50 percent when enacted but steadily increased the capture rate requirement to 90 percent in 2017, where it remains.

Michigan in 2023 established a 100 percent clean energy requirement by 2040 with a nearer term 80 percent clean energy by 2035 requirement.[350] The statute encourages the application of CCS by defining ''clean energy'' to include generation resources that achieve 90 percent carbon capture.

California identifies carbon capture and sequestration as a necessary tool to reduce GHG emissions within its 2022 scoping plan update [351] and, that same year, enacted a statutory requirement through Assembly Bill 1279 [352] requiring the state to plan and implement policies that enable carbon capture and storage technologies.

Several states in different parts of the country have adopted strategic and planning frameworks that also encourage CCS. Louisiana, which in 2020 set an economy-wide net-zero goal by 2050, has explored policies that encourage CCS deployment in the power sector. The state's 2022 Climate Action Plan proposes a Renewable and Clean Portfolio Standard requiring 100 percent renewable or clean energy by 2035.[353] That proposal defines power plants achieving 90 percent carbon capture as a qualifying clean energy resource that can be used to meet the standard.

Pennsylvania's 2021 Climate Action Plan notes that the state is well positioned to install CCS to transition the state's electric fleet to a zero-carbon economy.[354] The state also established an interagency workgroup in 2019 to identify ways to speed the deployment of CCS.

The Governor of North Dakota announced in 2021 an economy-wide carbon neutral goal by 2030.[355] The announcement singled out the Project Tundra Initiative, which is working to apply CCS technology to the state's Milton R. Young Power Station.

The Governor of Wyoming has broadly promoted a Decarbonizing the West initiative that includes the study of CCS technologies to reduce carbon emissions from the region.[356] A 2024 Wyoming law also requires utilities in the state to install CCS technologies on a portion of their existing coal-fired power plants by 2033.[357]

(6) Variable Load and Startups and Shutdowns

In this section of the preamble, the EPA considers the effects of variable load and startups and shutdowns on the achievability of 90 percent capture. First, the coal-fired steam generating unit can itself turndown [358] to only about 40 percent of its maximum design capacity. Due to this, coal-fired EGUs have relatively high duty cycles [359]—that is, they do not cycle as frequently as other sources and typically have high average loads when operating. In 2021, coal-fired steam generating units had an average duty cycle of 70 percent, and more than 75 percent of units had duty cycles greater than 60 percent.[360] Prior demonstrations of CO_2 capture plants on coal-fired steam generating units have had turndown limits of approximately 60 percent of throughput for Boundary Dam Unit 3 [361] and about 70 percent throughput for Petra Nova.[362] Based on the technology currently available, turndown to throughputs of 50 percent [363] are achievable for a single capture train.[364] Considering that coal units can typically only turndown to 40 percent, a 50 percent turndown ratio for the CO_2 capture plant is likely sufficient for most sources, although utilizing two CO_2 capture trains would allow for turndown to as low as 25 percent of throughput. When operating at less than maximum throughputs, the CO_2 capture facility actually achieves higher capture efficiencies, as evidenced by the data collected at Boundary Dam Unit 3.[365] Data from the Shand Feasibility Report suggests that, for a solvent and design achieving 90 percent capture at 100 percent of net load, 97.5 percent capture is achievable at 62.5 percent of net load.[366] Considering these factors, CO_2 capture is, in general, able to meet the variable load of coal-fired steam generating units without any adverse impact on the CO_2 capture rate. In fact, operation at lower loads may lead to

[348] State of Illinois General Assembly. Public Act 102–0662: Climate and Equitable Jobs Act. 2021. *https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf.*

[349] State of Illinois General Assembly. Public Act 095–1027: Clean Coal Portfolio Standard Law. *https://www.ilga.gov/legislation/publicacts/95/PDF/095-1027.pdf.*

[350] State of Michigan Legislature. Public Act 235 of 2023. Clean and Renewable Energy and Energy Waste Reduction Act. *https://legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0235.pdf.*

[351] California Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality. *https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.*

[352] State of California Legislature. Assembly Bill 1279 (2022). The California Climate Crisis Act. *https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB1279.*

[353] Louisiana Climate Initiatives Task Force. Louisiana Climate Action Plan (February 1, 2022). *https://gov.louisiana.gov/assets/docs/CCI-Task-force/CAP/ClimateActionPlanFinal.pdf.*

[354] Pennsylvania Dept. of Environmental Protection. Pennsylvania Climate Action Plan (2021). *https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx.*

[355] *https://www.governor.nd.gov/news/updated-waudio-burgum-addresses-williston-basin-petroleum-conference-issues-carbon-neutral.*

[356] *https://westgov.org/initiatives/overview/decarbonizing-the-west.*

[357] State of Wyoming Legislature. SF0042. Low-carbon Reliable Energy Standards-amendments. *https://www.wyoleg.gov/Legislation/2024/SF0042.*

[358] Here, ''turndown'' is the ability of a facility to turn down some process value, such as flowrate, throughput or capacity. Typically, this is expressed as a ratio relative to operation at its maximum instantaneous capability. Because processes are designed to operate within specific ranges, turndown is typically limited by some lower threshold.

[359] Here, ''duty cycle'' is the ratio of the gross amount of electricity generated relative to the amount that could be potentially generated if the unit operated at its nameplate capacity during every hour of operation. Duty cycle is thereby an indication of the amount of cycling or load following a unit experiences (higher duty cycles indicate less cycling, *i.e.,* more time at nameplate capacity when operating). Duty cycle is different from capacity factor, as the latter also quantifies the amount that the unit spends offline.

[360] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data website: *https://campd.epa.gov.*

[361] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *Reducing the CO_2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[362] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[363] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

[364] Here, a ''train'' in this context is a series of connected sequential process equipment. For carbon capture, a process train can include the quencher, absorber, stripper, and compressor. Rather than doubling the size of a single train of process equipment, a source could use two equivalent sized trains.

[365] Jacobs, B., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *Reducing the CO^2 Emission Intensity of Boundary Dam Unit 3 Through Optimization of Operating Parameters of the Power Plant and Carbon Capture Facilities. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4286430.*

[366] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.*

higher achievable capture rates over long periods of time.

Coal-fired steam generating units also typically have few startups and shutdowns per year, and CO_2 emissions during those periods are low. Although capacity factor has declined in recent years, as noted in section IV.D.3 of the preamble, the number of startups per year has been relatively stable. In 2011, coal-fired sources had about 10 startups on average. In 2021, coal-fired steam generating units had only 12 startups on average, see the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket. Prior to generation of electricity, coal-fired steam generating units use natural gas or distillate oil—which have a lower carbon content than coal—because of their ignition stability and low ignition temperature. Heat input rates during startup are relatively low, to slowly raise the temperature of the boiler. Existing natural gas- or oil-fired ignitors designed for startup purposes are generally sized for up to 15 percent of the maximum heat-input. Considering the low heat input rate, use of fuel with a lower carbon content, and the relatively few startups per year, the contribution of startup to total GHG emissions is relatively low. Shutdowns are relatively short events, so that the contribution to total emissions are also low. The emissions during startup and shutdown are therefore small relative to emissions during normal operation, so that any impact is averaged out over the course of a year.

Furthermore, the IRC section 45Q tax credit provides incentive for units to operate more. Sources operating at higher capacity factors are likely to have fewer startups and shutdowns and spend less time at low loads, so that their average load would be higher. This would further minimize the insubstantial contribution of startups and shutdowns to total emissions. Additionally, as noted in the preceding sections of the preamble, new solvents achieve capture rates of 95 percent at full load, and ongoing projects are targeting capture rates of 95 percent. Considering all of these factors, startup and shutdown, in general, do not affect the achievability of 90 percent capture over long periods (*i.e.,* a year).

(7) Coal Rank

CO_2 capture at coal-fired steam generating units achieves 90 percent capture, for the reasons detailed in sections VII.C.1.a.i(B)(1) through (6) of this preamble. Moreover, 90 percent capture is achievable for all coal types because amine solvents have been used to remove CO_2 from a variety of flue gas compositions including a broad range of different coal ranks, differences in CO_2 concentration are slight and the capture process can be designed to the appropriate scale, amine solvents have been used to capture CO_2 from flue gas with much lower CO_2 concentrations, and differences in flue gas impurities due to different coal compositions can be managed or mitigated by controls.

As detailed in the preceding sections, CO_2 capture has been operated on flue gas from the combustion of a broad range of coal ranks including lignite, bituminous, subbituminous, and anthracite coals. Post-combustion CO_2 capture from the flue gas of an EGU firing lignite has been demonstrated at the Boundary Dam Unit 3 EGU (Saskatchewan, Canada). Most lignites have a higher ash and moisture content than other coal types and, in that respect, the flue gas can be more challenging to manage for CO_2 capture. Amine CO_2 capture has also been used to treat lignite post-combustion flue gas in pilot studies at the Milton R. Young station (North Dakota).[367] CO_2 capture solvents have been used to treat subbituminous post-combustion flue gas from W.A. Parish Generating Station (Texas),[368] and the bituminous post-combustion flue gas from Plant Barry (Mobile, Alabama),[369] Warrior Run (Maryland),[370] and Argus Cogeneration Plant (California).[371] Amine solvents have also been used to remove CO_2 from the flue gas of the bituminous- and subbituminous-fired Shady Point plant.[372] CO_2 capture solvents have been used to treat anthracite post-combustion flue gas at the Wilhelmshaven power plant (Germany).[373] There are also ongoing projects that will apply CCS to the flue gas of coal-fired steam generating units. The EPA considers these ongoing projects to be indicative of the confidence that industry stakeholders have in CCS. These include Project Tundra at the lignite-fired Milton R. Young station (North Dakota),[374] Project Diamond Vault at the petroleum coke- and subbituminous-fired Brame Energy Center Madison Unit 3 (Louisiana) [375] and two units at the Jim Bridger Plant (Wyoming).[376]

Different coal ranks have different carbon contents, affecting the concentration of CO_2 in flue gas. In general, however, CO_2 concentration of coal combustion flue gas varies only between 13 and 15 percent. Differences in CO_2 concentration can be accounted for by appropriately designing the capture equipment, including sizing the absorber columns. As detailed in section VIII.F.4.c.iv of the preamble, CO_2 has been captured from the post-combustion flue gas of NGCCs, which typically have a CO_2 concentration of 4 percent.

Prior to emission controls and pre-conditioning, characteristics of different coal ranks and boiler design result in other differences in the flue gas composition, including in the concentration of SO_2, NO_X, PM, and trace impurities. Such impurities in the flue gas can react with the solvent or cause fouling of downstream processes. However, in general, most existing coal-fired steam generating units in the U.S. have controls that are necessary for the pre-conditioning of flue gas prior to the CO_2 capture plant, including PM and SO_2 controls. For those sources without an FGD for SO_2 control, the EPA included the costs of adding an FGD in its cost analysis. Other marginal differences in flue gas impurities can be managed by appropriately designing the polishing column (direct contact cooler) for the individual source's flue gas. Trace impurities can be mitigated using conventional controls in the solvent reclaiming process (*e.g.,* an activated carbon bed).

Considering the broad range of coal post-combustion flue gases amine solvents have been operated with, that solvents capture CO_2 from flue gases with lower CO_2 concentrations, that the capture process can be designed for different CO_2 concentrations, and that flue gas impurities that may differ by coal rank can be managed by controls, the EPA therefore concludes that 90 percent capture is achievable across all coal ranks, including waste coal.

[367] Laum, Jason. Subtask 2.4—Overcoming Barriers to the Implementation of Postcombustion Carbon Capture. *https://www.osti.gov/biblio/1580659.*

[368] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020). *https://www.osti.gov/servlets/purl/1608572.*

[369] U.S. Department of Energy (DOE). National Energy Technology Laboratory (NETL). *https://www.netl.doe.gov/node/1741.*

[370] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[371] *Id.*

[372] *Id.*

[373] Reddy, *et al.* Energy Procedia, 37 (2013) 6216–6225.

[374] Project Tundra—Progress, Minnkota Power Cooperative, 2023. *https://www.projecttundrand.com.*

[375] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[376] 2023 Integrated Resource Plan Update, PacifiCorp, April 1, 2024, *https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023_IRP_Update.pdf.*

(8) Natural Gas-Fired Combustion Turbines

Additional information supporting the EPA's determination that 90 percent capture of CO_2 from steam generating units is adequately demonstrated is the experience from CO_2 capture from natural gas-fired combustion turbines. The EPA describes this information in section VIII.F.4.c.iv(B)(1), including explaining how information about CO_2 capture from coal-fired steam generating units also applies to natural gas-fired combustion turbines. The reverse is true as well; information about CO_2 capture from natural gas-fired turbines can be applied to coal fired-units, for much the same reasons.

(9) Summary of Evidence Supporting BSER Determination Without EPAct05-Assisted Projects

As noted above, under the EPA's interpretation of the EPAct05 provisions, the EPA may not rely on capture projects that received assistance under EPAct05 as the sole basis for a determination of adequate demonstration, but the EPA may rely on those projects to support or corroborate other information that supports such a determination. The information described above that supports the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated, without consideration of the EPAct05-assisted projects, includes (i) the information concerning Boundary Dam, coupled with engineering analysis concerning key improvements that can be implemented in future CCS deployments during initial design and construction (*i.e.,* all the information in section VII.C.1.a.i.(B)(1)(a) and the information concerning Boundary Dam in section VII.C.1.a.i.(B)(1)(b)); (ii) the information concerning other coal-fired demonstrations, including the Argus Cogeneration Plant and AES's Warrior Run (*i.e.,* all the information concerning those sources in section VII.C.1.a.i.(B)(1)(a)); (iii) the information concerning industrial applications of CCS (*i.e.,* all the information in section VII.C.1.a.i.(A)(1); (iv) the information concerning CO_2 capture technology vendor statements (*i.e.,* all the information in section VII.C.1.a.i.(B)(3)); (v) information concerning carbon capture at natural gas-fired combustion turbines other than EPAct05-assisted projects (*i.e.,* all the information other than information about EPAct05-assisted projects in section VIII.F.4.c.iv.(B)(1)). All this information by itself is sufficient to support the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated. Substantial additional information from EPAct05-assisted projects, as described in section VII.C.1.a.i.(B), provides additional support and confirms that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated.

(C) CO_2 Transport

The EPA is finalizing its determination that CO_2 transport by pipelines as a component of CCS is adequately demonstrated. The EPA anticipates that in the coming years, a large-scale interstate pipeline network may develop to transport CO_2. Indeed, PHMSA is currently engaged in a rulemaking to update and strengthen its safety regulations for CO_2 pipelines, which assumes that such a pipeline network will develop.[377] For purposes of determining the CCS BSER in this final action, however, the EPA did not base its analysis of the availability of CCS on the projected existence of a large-scale interstate pipeline network. Instead, the EPA adopted a more conservative approach. The BSER is premised on the construction of relatively short lateral pipelines that extend from the source to the nearest geologic storage reservoir. While the EPA anticipates that sources would likely avail themselves of an existing interstate pipeline network if one were constructed and that using an existing network would reduce costs, the EPA's analysis focuses on steps that an individual source could take to access CO_2 storage independently.

EGUs that do not currently capture and transport CO_2 will need to construct new CO_2 pipelines to access CO_2 storage sites, or make arrangements with pipeline owners and operators who can do so. Most coal-fired steam EGUs, however, are located in relatively close proximity to deep saline formations that have the potential to be used as long-term CO_2 storage sites.[378] Of existing coal-fired steam generating capacity with planned operation during or after 2039, more than 50 percent is located less than 32 km (20 miles) from potential deep saline sequestration sites, 73 percent is located within 50 km (31 miles), 80 percent is located within 100 km (62 miles), and 91 percent is within 160 km (100 miles). While the EPA's analysis focuses on the geographic availability of deep saline formations, unmineable coal seams and depleted oil and gas reservoirs could also potentially serve as storage formations depending on site-specific characteristics. Thus, for the majority of sources, only relatively short pipelines would be needed for transporting CO_2 from the source to the sequestration site. For the reasons described below, the EPA believes that both new and existing EGUs are capable of constructing CO_2 pipelines as needed. New EGUs may also be planned to be co-located with a storage site so that minimal transport of the CO_2 is required. The EPA has assurance that the necessary pipelines will be safe because the safety of existing and new supercritical CO_2 pipelines is comprehensively regulated by PHMSA.[379]

(1) CO_2 Transport Demonstrations

The majority of CO_2 transported in the United States is moved through pipelines. CO_2 pipelines have been in use across the country for nearly 60 years. Operation of this pipeline infrastructure for this period of time establishes that the design, construction, and operational requirements for CO_2 pipelines have been adequately demonstrated.[380] PHMSA reported that 8,666 km (5,385 miles) of CO_2 pipelines were in operation in 2022, a 14 percent increase in CO_2 pipeline miles since 2011.[381] This pipeline infrastructure continues to expand with a number of anticipated projects underway.

The U.S. CO_2 pipeline network includes major trunkline (*i.e.,* large capacity) pipelines as well as shorter, smaller capacity lateral pipelines connecting a CO_2 source to a larger trunkline or connecting a CO_2 source to a nearby CO_2 end use. While CO_2

[377] PHMSA submitted the associated Notice of Proposed Rulemaking to the White House Office of Management and Budget on February 1, 2024 for pre-publication review. The notice stated that the proposed rulemaking would enhance safety regulations to ''accommodate an anticipated increase in the number of carbon dioxide pipelines and volume of carbon dioxide transported.'' Office of Management and Budget. *https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202310&RIN=2137-AF60.*

[378] Individual saline formations would require site-specific characterization to determine their suitability for geologic sequestration and the potential capacity for storage.

[379] PHMSA additionally initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of CO_2 pipelines following investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020. For more information, see: *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[380] For additional information on CO_2 transportation infrastructure project timelines, costs and other details, please see EPA's final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[381] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

pipelines are generally more economical, other methods of CO_2 transport may also be used in certain circumstances and are detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

(a) Distance of CO_2 Transport for Coal-Fired Power Plants

An important factor in the consideration of the feasibility of CO_2 transport from existing coal-fired steam generating units to sequestration sites is the distance the CO_2 must be transported. As discussed in section VII.C.1.a.i(D), potential sequestration formations include deep saline formations, unmineable coal seams, and oil and gas reservoirs. Based on data from DOE/NETL studies of storage resources, of existing coal-fired steam generating capacity with planned operation during or after 2039, 80 percent is within 100 km (62 miles) of potential deep saline sequestration sites, and another 11 percent is within 160 km (100 miles).[382] In other words, 91 percent of this capacity is within 160 km (100 miles) of potential deep saline sequestration sites. In gigawatts, of the 81 GW of coal-fired steam generation capacity with planned operation during or after 2039, only 16 GW is not within 100 km (62 miles) of a potential saline sequestration site, and only 7 GW is not within 160 km (100 mi). The vast majority of these units (on the order of 80 percent) can reach these deep saline sequestration sites by building an intrastate pipeline. This distance is consistent with the distances referenced in studies that form the basis for transport cost estimates for this final rule.[383] While the EPA's analysis focuses on the geographic availability of deep saline formations, unmineable coal seams and depleted oil and gas reservoirs could also potentially serve as storage formations depending on site-specific characteristics.

Of the 9 percent of existing coal-fired steam generating capacity with planned operation during or after 2039 that is not within 160 km (100 miles) of a potential deep saline sequestration site, 5 percent is within 241 km (150 miles) of potential saline sequestration sites, an additional 3 percent is within 322 km (200 miles) of potential saline sequestration sites, and another 1 percent is within 402 km (250 miles) of potential sequestration sites. In total, assuming all existing coal-fired steam generating capacity with planned operation during or after 2039 adopts CCS, the EPA analysis shows that approximately 8,000 km (5,000 miles) of CO_2 pipelines would be constructed by 2032. This includes units located at any distance from sequestration. Note that this value is not optimized for the least total pipeline length, but rather represents the approximate total pipeline length that would be required if each power plant constructed a lateral pipeline connecting their power plant to the nearest potential saline sequestration site.[384]

Additionally, the EPA's compliance modeling projects 3,300 miles of CO_2 pipeline buildout in the baseline and 4,700 miles of pipeline buildout in the policy scenario. This is comparable to the 4,700 to 6,000 miles of CO_2 pipeline buildout estimated by other simulations examining similar scenarios of coal CCS deployment.[385] Over 5 years, this total projected CO_2 pipeline capacity would amount to about 660 to 940 miles per year on average.[386] This projected pipeline mileage is comparable to other types of pipelines that are regularly constructed in the United States each year. For example, based on data collected by EIA, the total annual mileage of natural gas pipelines constructed over the 2017–2021 period ranged from approximately 1,000 to 2,500 miles per year. The projected annual average CO_2 pipeline mileage is less than each year in this historical natural gas pipeline range, and significantly less than the upper end of this range.

The EPA also notes that the pipeline construction estimates presented in this section are not additive with the natural gas co-firing pipeline construction estimates presented below because individual sources will not elect to utilize both compliance methods. In other words, more pipeline buildout for one compliance method necessarily means less pipeline buildout for the other method. Therefore, there is no compliance scenario in which the total pipeline construction is equal to the sum of the CCS and natural gas co-firing pipeline estimates presented in this preamble.

While natural gas line construction may be easier in some circumstances given the uniform federal regulation that governs those such construction, the historical trends support the EPA's conclusion that constructing less CO_2 pipeline length over a several year period is feasible.

(b) CO_2 Pipeline Examples

PHMSA reported that 8,666 km (5,385 miles) of CO_2 pipelines were in operation in 2022.[387] Due to the unique nature of each project, CO_2 pipelines vary widely in length and capacity. Examples of projects that have utilized CO_2 pipelines include the following: Beaver Creek (76 km), Monell (52.6 km), Bairoil (258 km), Salt Creek (201 km), Sheep Mountain (656 km), Slaughter (56 km), Cortez (808 km), Central Basin (231 km), Canyon Reef Carriers (354 km), and Choctaw (294 km). These pipelines range in capacity from 1.6 million tons per year to 27 million tons per year, and transported CO_2 for uses such as EOR.[388]

Most sources deploying CCS are anticipated to construct pipelines that run from the source to the sequestration site. Similar CO_2 pipelines have been successfully constructed and operated in the past. For example, a 109 km (68 mile) CO_2 pipeline was constructed from a fertilizer plant in Coffeyville, Kansas, to the North Burbank Unit, an EOR operation in Oklahoma.[389] Chaparral Energy entered a long-term CO_2 purchase and sale agreement with a subsidiary of CVR Energy for the capture of CO_2 from CVR's nitrogen fertilizer plant in 2011.[390] The pipeline

[382] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[383] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[384] Note that multiple coal-fired EGUs may be located at each power plant.

[385] CO_2 Pipeline Analysis for Existing Coal-Fired Powerplants. Chen et. al. Los Alamos National Lab. 2024. *https://permalink.lanl.gov/object/tr?what=info:lanl-repo/lareport/LA-UR-24-23321.*

[386] In the EPA's representative timeline, the CO_2 pipeline is constructed in an 18-month period. In practice, all CO_2 pipeline construction projects would be spread over a larger time period. In the Transport and Storage Timeline Summary, ICF (2024), available in Docket ID EPA–HQ–OAR–2023–0072, permitting is 1.5 years. Some CO_2 pipeline construction would therefore likely begin by the start of 2028, or even earlier considering on-going projects. With the one-year compliance extension for delays outside of the owner/operators control that would provide extra time if there were challenges in building pipelines, the construction on CO_2 pipelines could occur during 2032.

[387] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[388] Noothout, Paul. Et. Al. (2014). ''CO_2 Pipeline infrastructure—lessons learnt.'' *https://www.sciencedirect.com/science/article/pii/S187661021402864.*

[389] Rassenfoss, Stephen. (2014). ''Carbon Dioxide: From Industry to Oil Fields.'' *ttps://jpt.spe.org/carbon-dioxide-industry-oil-fields.*

[390] GlobeNewswire. ''Chaparral Energy Agrees to a CO2 Purchase and Sale Agreement with CVR Energy for Capture of CO_2 for Enhanced Oil Recovery.'' March 29, 2011. *https://www.globenewswire.com/news-release/2011/03/29/443163/10562/en/Chaparral-Energy-Agrees-to-a-CO2-Purchase-and-Sale-Agreement-With-CVR-*

was then constructed, and operations started in 2013.[391] Furthermore, a 132 km (82 mile) pipeline was constructed from the Terrell Gas facility (formerly Val Verde) in Texas to supply CO_2 for EOR projects in the Permian Basin.[392] Additionally, the Kemper Country CCS project in Mississippi, was designed to capture CO_2 from an integrated gasification combined cycle power plant, and transport CO_2 via a 96 km (60 mile) pipeline to be used in EOR.[393] Construction for this facility commenced in 2010 and was completed in 2014.[394] Furthermore, the Citronelle Project in Alabama, which was the largest demonstration of a fully integrated, pulverized coal-fired CCS project in the United States as of 2016, utilized a dedicated 19 km (12 mile) pipeline constructed by Denbury Resources in 2011 to transport CO_2 to a saline storage site.[395]

(c) EPAct05-Assisted CO_2 Pipelines for CCS

Consistent with the EPA's legal interpretation that the Agency can rely on experience from EPAct05 funded facilities in conjunction with other information, this section provides additional examples of CO_2 pipelines with EPAct05 funding. CCS projects with EPAct05 funding have built pipelines to connect the captured CO_2 source with sequestration sites, including Illinois Industrial Carbon Capture and Storage in Illinois, Petra Nova in Texas, and Red Trail Energy in North Dakota. The Petra Nova project, which restarted operations in September 2023,[396] transports CO_2 via a 131 km (81 mile) pipeline to the injection site, while the Illinois Industrial Carbon Capture project and Red Trail Energy transport CO_2 using pipelines under 8 km (5 miles) long.[397] [398] [399] Additionally, Project Tundra, a saline sequestration project planned at the lignite-fired Milton R. Young Station in North Dakota will transport CO_2 via a 0.4 km (0.25 mile) pipeline.[400]

(d) Existing and Planned CO_2 Trunklines

Although the BSER is premised on the construction of pipelines that connect the CO_2 source to the sequestration site, in practice some sources may construct short laterals to existing CO_2 trunklines, which can reduce the number of miles of pipeline that may need to be constructed. A map displaying both existing and planned CO_2 pipelines, overlayed on potential geologic sequestration sites, is available in the final TSD, *GHG Mitigation Measures for Steam Generating Units.* Pipelines connect natural CO_2 sources in south central Colorado, northeast New Mexico, and Mississippi to oil fields in Texas, Oklahoma, New Mexico, Utah, and Louisiana. The Cortez pipeline is the longest CO_2 pipeline, and it traverses over 800 km (500) miles from southwest Colorado to Denver City, Texas CO_2 Hub, where it connects with several other CO_2 pipelines. Many existing CO_2 pipelines in the U.S. are located in the Permian Basin region of west Texas and eastern New Mexico. CO_2 pipelines in Wyoming, Texas, and Louisiana also carry CO_2 captured from natural gas processing plants and refineries to EOR projects. Additional pipelines have been constructed to meet the demand for CO_2 transportation. A 170 km (105 mile) CO_2 pipeline owned by Denbury connecting oil fields in the Cedar Creek Anticline (located along the Montana-North Dakota border) to CO_2 produced in Wyoming was completed in 2021, and a 30 km (18 mile) pipeline also owned by Denbury connects to the same oil field and was completed in 2022.[401] [402] These pipelines form a network with existing pipelines in the region—including the Denbury Greencore pipeline, which was completed in 2012 and is 232 miles long, running from the Lost Cabin gas plant in Wyoming to Bell Creek Field in Montana.[403]

In addition to the existing pipeline network, there are a number of large CO_2 trunklines that are planned or in progress, which could further reduce the number of miles of pipeline that a source may need to construct. Several major projects have recently been announced to expand the CO_2 pipeline network across the United States. For example, the Summit Carbon Solutions Midwest Carbon Express project has proposed to add more than 3,200 km (2,000) miles of dedicated CO_2 pipeline in Iowa, Nebraska, North Dakota, South Dakota, and Minnesota. The Midwest Carbon Express is projected to begin operations in 2026. Further, Wolf Carbon Solutions has recently announced that it plans to refile permit applications for the Mt. Simon Hub, which will expand the CO_2 pipeline by 450 km (280 miles) in the Midwest. Tallgrass announced in 2022 a plan to convert an existing 630 km (392 mile) natural gas pipeline to carry CO_2 from an ADM ethanol production facility in Nebraska to a planned commercial-scale CO_2 sequestration hub in Wyoming aimed for completion in 2024.[404] Recently, as part of agreeing to a communities benefits plan, a number of community groups have agreed that they will support construction of the Tallgrass pipeline in Nebraska.[405] While the construction of larger networks of trunklines could facilitate CCS for power plants, the BSER is not predicated on the buildout of a trunkline network and the existence of future trunklines was not assumed in the EPA's feasibility or costing analysis. The EPA's analysis is conservative in that it does not presume the buildout of trunkline networks. The development of more robust and interconnected pipeline systems over the next several years would merely lower the EPA's

Energy-for-Capture-of-CO2-for-Enhanced-Oil-Recovery.html.

[391] Chaparral Energy. ''A 'CO_2 Midstream' Overview: EOR Carbon Management Workshop.'' December 10, 2013. *https://www.co2conference.net/wp-content/uploads/2014/01/13-Chaparral-CO2-Midstream-Overview-2013.12.09new.pdf.*

[392] ''Val Verde Fact Sheet: Commercial EOR using Anthropogenic Carbon Dioxide.'' *https://sequestration.mit.edu/tools/projects/val_verde.html.*

[393] Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project. *https://sequestration.mit.edu/tools/projects/kemper.html.*

[394] Office of Fossil Energy and Carbon Management. Southern Company—Kemper County, Mississippi. *https://www.energy.gov/fecm/southern-company-kemper-county-mississippi.*

[395] Citronelle Project. National Energy Technology Laboratory. (2018). *https://www.netl.doe.gov/sites/default/files/2018-11/Citronelle-SECARB-Project.PDF.*

[396] Jacobs, Trent. (2023). ''A New Day Begins for Shuttered Petra Nova CCUS.'' *https://jpt.spe.org/a-new-day-begins-for-shuttered-petra-nova-ccus.*

[397] Technical Review of Subpart RR MRV Plan for Petra Nova West Ranch Unit. (2021). *https://www.epa.gov/system/files/documents/2021-09/wru_decision.pdf.*

[398] Technical Review of Subpart RR MRV Plan for Archer Daniels Midland Illinois Industrial Carbon Capture and Storage Project. (2017). *https://www.epa.gov/sites/default/files/2017-01/documents/adm_final_decision.pdf.*

[399] Red Trail Energy Subpart RR Monitoring, Reporting, and Verification (MRV) Plan. (2022). *https://www.epa.gov/system/files/documents/2022-04/rtemrvplan.pdf.*

[400] Technical Review of Subpart RR MRV Plan for Tundra SGS LLC at the Milton R. Young Station. (2022). *https://www.epa.gov/system/files/documents/2022-04/tsgsdecision.pdf.*

[401] Denbury. Detailed Pipeline and Ownership Information. (2022) *https://www.denbury.com/wp-content/uploads/2022/11/DEN-Pipeline-Schedule.pdf.*

[402] AP News. Officials mark start of CO_2 pipeline used for oil recovery. (2022) *https://apnews.com/article/business-texas-north-dakota-plano-25f1dbf9a924613a56827c1c83e4ba68.*

[403] Denbury. Detailed Pipeline and Ownership Information. (2022) *https://www.denbury.com/wp-content/uploads/2022/11/DEN-Pipeline-Schedule.pdf.*

[404] Tallgrass. Tallgrass to Capture and Sequester CO_2 Emissions from ADM Corn Processing Complex in Nebraska. (2022). *https://tallgrass.com/newsroom/press-releases/tallgrass-to-capture-and-sequester-co2-emissions-from-adm-corn-processing-complex-in-nebraska.*

[405] *https://boldnebraska.org/upcoming-meetings-understanding-the-new-tallgrass-carbon-pipeline-community-benefits-agreement/.*

cost projections and create additional CO_2 transport options for power plants that do CCS.

Moreover, pipeline projects have received funding under the IIJA to conduct front-end engineering and design (FEED) studies.[406] Carbon Solutions LLC received funding to conduct a FEED study for a commercial-scale pipeline to transport CO_2 in support of the Wyoming Trails Carbon Hub as part of a statewide pipeline system that would be capable of transporting up to 45 million metric tons of CO_2 per year from multiple sources. In addition, Howard Midstream Energy Partners LLC received funding to conduct a FEED study for a 965 km (600 mi) CO_2 pipeline system on the Gulf Coast that would be capable of moving at least 250 million metric tons of CO_2 annually and connecting carbon sources within 30 mi of the trunkline.

Other programs were created by the IIJA to facilitate the buildout of large pipelines to carry carbon dioxide from multiple sources. For example, the Carbon Dioxide Transportation Infrastructure Finance and Innovation Act (CIFIA) was incorporated into the IIJA and provided $2.1 billion to DOE to finance projects that build shared (*i.e.,* common carrier) transport infrastructure to move CO_2 from points of capture to conversion facilities and/or storage wells. The program offers direct loans, loan guarantees, and ''future growth grants'' to provide cash payments to specifically for eligible costs to build additional capacity for potential future demand.[407]

(2) Permitting and Rights of Way

The permitting process for CO_2 pipelines often involves a number of private, local, state, tribal, and/or Federal agencies. States and local governments are directly involved in siting and permitting proposed CO_2 pipeline projects. CO_2 pipeline siting and permitting authorities, landowner rights, and eminent domain laws are governed by the states and vary by state.

State laws determine pipeline siting and the process for developers to acquire rights-of-way needed to build. Pipeline developers may secure rights-of-way for proposed projects through voluntary agreements with landowners; pipeline developers may also secure rights-of-way through eminent domain authority, which typically accompanies siting permits from state utility regulators with jurisdiction over CO_2 pipeline siting.[408] The permitting process for interstate pipelines may take longer than for intrastate pipelines. Whereas multiple state regulatory agencies would be involved in the permitting process for an interstate pipeline, only one primary state regulatory agency would be involved in the permitting process for an intrastate pipeline.

Most regulation of CO_2 pipeline siting and development is conducted at the state level, and under state specific regulatory regimes. As the interest in CO_2 pipelines has grown, states have taken steps to facilitate pipeline siting and construction. State level regulation related to CO_2 sequestration and transport is an very active area of legislation across states in all parts of the country, with many states seeking to facilitate pipeline siting and construction.[409] Many states, including Kentucky, Michigan, Montana, Arkansas, and Rhode Island, treat CO_2 pipeline operators as common carriers or public utilities.[410] This is an important classification in some jurisdictions where it may be required for pipelines seeking to exercise eminent domain.[411] Currently, 17 states explicitly allow CO_2 pipeline operators to exercise eminent domain authority for acquisition of CO_2 pipeline rights-of-way, should developers not secure them through negotiation with landowners.[412] Some states have recognized the need for a streamlined CO_2 pipeline permitting process when there are multiple layers of regulation and developed joint permit applications. Illinois, Louisiana, New York, and Pennsylvania have created a joint permitting form that allows applicants to file a single application for pipeline projects covering both state and federal permitting requirements.[413] Even in states without this streamlined process, pipeline developers can pursue required state permits concurrently with federal permits, NEPA review (as applicable), and the acquisition of rights-of-way.

Pipeline developers have been able to successfully secure the necessary rights-of way for CO_2 pipeline projects. For example, Summit Carbon Solutions, which has proposed to add more than 3,200 km (2,000 mi) of dedicated CO_2 pipeline in Iowa, Nebraska, North Dakota, South Dakota, and Minnesota, has stated that as of November 7, 2023, it had reached easement agreements with 2,100 landowners along the route.[414] As of February 23, 2024, Summit Carbon Solutions stated that it had acquired about 75 percent of the rights of way needed in Iowa, about 80 percent in North Dakota, about 75 percent in South Dakota, and about 89 percent in Minnesota. The company has successfully navigated hurdles, such as rerouting the pipelines in certain counties where necessary.[415] [416] The EPA notes that this successful acquisition of right-of-way easements for thousands of miles of pipeline across five states has taken place in just the three years since the project launched in 2021.[417] In addition, the Citronelle Project, which was constructed in Alabama in 2011, successfully acquired rights-of-way through 9 miles of forested and commercial timber land and 3 miles of emergent shrub and forested wetlands. The Citronelle Project was able to attain rights-of-way through the habitat of an endangered species by mitigating potential environmental

[406] Office of Fossil Energy and Carbon Management. ''Project Selections for FOA 2730: Carbon Dioxide Transport Engineering and Design (Round 1).'' *https://www.energy.gov/fecm/project-selections-foa-2730-carbon-dioxide-transport-engineering-and-design-round-1.*

[407] *https://www.energy.gov/lpo/carbon-dioxide-transportation-infrastructure.*

[408] Congressional Research Service.2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June 3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[409] Great Plains Institute State Legislative Tracker 2023. Carbon Management State Legislative Program Tracker. *https://www.quorum.us/spreadsheet/external/fVOjsTvwyeWkIqVlNmoq/?mc_cid=915706f2bc&.*

[410] National Association of Regulatory Utility Commissioners (NARUC). (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[411] Martin Lockman. *Permitting CO_2 Pipelines.* Sabin Center for Climate Change Law (2023). *https://scholarship.law.columbia.edu/cgi/viewcontent.cgi?article=1208&context=sabin_climate_change.*

[412] The 17 states are: Arizona, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Montana, New Mexico, North Carolina, North Dakota, Pennsylvania, South Dakota, Texas, and Wyoming. National Association of Regulatory Utility Commissioners (NARUC). (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[413] Martin Lockman. *Permitting CO_2 Pipelines.* Sabin Center for Climate Change Law (Sept. 2023). *https://scholarship.law.columbia.edu/cgi/viewcontent.cgi?article=1208&context=sabin_climate_change.*

[414] South Dakota Public Broadcasting. ''Summit reaches land deals on more than half of CO_2 pipeline route.'' (2022). *https://listen.sdpb.org/business-economics/2022-11-08/summit-reaches-land-deals-on-more-than-half-of-co2-pipeline-route.*

[415] Summit CEO: CO2 Pipeline's Time is Now. (2024). *https://www.dtnpf.com/agriculture/web/ag/news/business-inputs/article/2024/02/23/summit-ceo-blank-says-company-toward.*

[416] Summit Carbon Solutions. Summit Carbon Solutions Signs 80 Percent of North Dakota Landowners. (2023). *https://summitcarbonsolutions.com/summit-carbon-solutions-signs-80-percent-of-north-dakota-landowners/.*

[417] Summit Carbon Solutions. Summit Carbon Solutions Announces Progress on Carbon Capture and Storage Project. (2022). *https://summitcarbonsolutions.com/summit-carbon-solutions-announces-progress-on-carbon-capture-and-storage-project/.*

impacts.[418] Even projects that require rights-of-way across multiple ownership regimes including state, private, and federally owned land have been successfully developed. The 170 km (105 mile) Cedar Creek Anticline CO_2 pipeline owned by Denbury required easements for approximately 10 km (6.2 mi) to cross state school trust lands in Montana, 27 km (17 mi) across Federal land and the remaining miles across private lands.[419] [420] The pipeline was completed in 2021.[421]

Federal actions (*e.g.,* funding a CCS project) must generally comply with NEPA, which often requires that an environmental assessment (EA) or environmental impact statement (EIS) be conducted to consider environmental impacts of the proposed action, including consideration of reasonable alternatives.[422] An EA determines whether or not a Federal action has the potential to cause significant environmental effects. Each Federal agency has adopted its own NEPA procedures for the preparation of EAs.[423] If the agency determines that the action will not have significant environmental impacts, the agency will issue a Finding of No Significant Impact (FONSI). Some projects may also be ''categorically excluded'' from a detailed environmental analysis when the Federal action normally does not have a significant effect on the human environment. Federal agencies prepare an EIS if a proposed Federal action is determined to significantly affect the quality of the human environment. The regulatory requirements for an EIS are more detailed and rigorous than the requirements for an EA. The determination of the level of NEPA review depends on the potential for significant environmental impacts considering the whole project (*e.g.,* crossings of sensitive habitats, cultural resources, wetlands, public safety concerns). Consequently, whether a pipeline project is covered by NEPA and the associated permitting timelines may vary depending on site characteristics (*e.g.,* pipeline length, whether a project crosses a water of the U.S.) and funding source. Pipelines through Bureau of Land Management (BLM) land, U.S. Forest Service (USFS) land, or other Federal land would be subject to NEPA. To ensure that agencies conduct NEPA reviews as efficiently and expeditiously as practicable, the Fiscal Responsibility Act[424] amendments to NEPA established deadlines for the preparation of environmental assessments and environmental impact statements. Environmental assessments must be completed within 1 year and environmental impact statements must be completed within 2 years[425] A lead agency that determines it is not able to meet the deadline may extend the deadline, in consultation with the applicant, to establish a new deadline that provides only so much additional time as is necessary to complete such environmental impact statement or environmental assessment.[426]

As discussed above, it is anticipated that most EGUs would need shorter, intrastate pipeline segments. For example, ADM's Decatur, Illinois, pipeline, which spans 1.9 km (1.18 miles), was constructed after Decatur was selected for the DOE Phase 1 research and development grants in October 2009.[427] Construction of the CO_2 compression, dehydration, and pipeline facilities began in July 2011 and was completed in June 2013.[428] The ADM project required only an EA. Additionally, Air Products operates a large-scale system to capture CO_2 from two steam methane reformers located within the Valero Refinery in Port Arthur, Texas. The recovered and purified CO_2 is delivered by pipeline for use in enhanced oil recovery operations.[429] This 12-mile pipeline required only an EA.[430] Conversely, the Petra Nova project in Texas required an EIS to evaluate the potential environmental impacts associated with DOE's proposed action of providing financial assistance for the project. This EIS addressed potential impacts from both the associated 131 km (81 mile) pipeline and other aspects of the larger CCS system, including the post-combustion CO_2.[431] For Petra Nova, a notice of intent to issue an EIS was published on November 14, 2011, and the record of decision was issued less than 2 years later, on May 23, 2013.[432] Construction of the CO_2 pipeline for Petra Nova from the W.A. Parish Power Plant to the West Ranch Oilfield in Jackson County, TX began in July 2014 and was completed in July 2016.[433]

Compliance with section 7 of the Endangered Species Act related to Federal agency consultation and biological assessment is also required for projects on Federal lands. Specifically, the Endangered Species Act requires consultation with the Department of Interior's Fish and Wildlife Service and Department of Commerce's NOAA Fisheries, in order to avoid or mitigate impacts to any threatened or endangered species and their habitats.[434] This agency consultation process and biological assessment are generally conducted during preparation of the NEPA documentation (EIS or EA) for the Federal project and generally within the regulatory timeframes for environmental assessment or environmental impact statement preparation. Consequently, the EPA does not anticipate that compliance with the Endangered Species Act will change the anticipated timeline for most projects.

The EPA notes that the Fixing America's Surface Transportation Act (FAST Act) is also relevant to CCS projects and pipelines. Title 41 of this Act (42 U.S.C. 4370m *et seq.*), referred to as ''FAST–41,'' created a new

[418] SECARB. (2021). Final Project Report—SECARB Phase III, September 2021. *https://www.osti.gov/servlets/purl/1823250.*

[419] Great Falls Tribune. Texas company plans 110-mile CO_2 pipeline to enhance Montana oil recovery. (2018). *https://www.greatfallstribune.com/story/news/2018/10/09/texas-company-plans-co-2-pipeline-injection-free-montana-oil/1577657002/.*

[420] U.S. D.O.I B.L.M. Denbury-Green Pipeline-MT, LLC, Denbury Onshore, LLC Cedar Creek Anticline CO_2 Pipeline and EOR Development Project Scoping Report. *https://eplanning.blm.gov/public_projects/nepa/89883/137194/167548/BLM_Denbury_Projects_Scoping_Report_March2018.pdf.*

[421] AP News. Officials mark start of CO_2 pipeline used for oil recovery. (2022) *https://apnews.com/article/business-texas-north-dakota-plano-25f1dbf9a924613a56827c1c83e4ba68.*

[422] Council on Environmental Quality. (2024). CEQ NEPA Regulations. *https://ceq.doe.gov/laws-regulations/regulations.html.*

[423] Council of Environmental Quality. (2023). Agency NEPA Implementing Procedures. *https://ceq.doe.gov/laws-regulations/agency_implementing_procedures.html.*

[424] Public Law 118–5 (June 3, 2023).

[425] NEPA Sec. 107(g)(1); 42 U.S.C. 4336a(g)(1).

[426] NEPA sec. 107(g)(2); 42 U.S.C. 4336a(g)(2).

[427] Massachusetts Institute of Technology. (2014). Decatur Fact Sheet: Carbon Dioxide Capture and Storage Project. *https://sequestration.mit.edu/tools/projects/decatur.html.*

[428] NETL. ''CO2 Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone.'' Award #DE–FE0001547. *https://www.usaspending.gov/award/ASST_NON_DEFE0001547_8900.*

[429] Air Products. Carbon Capture. *https://www.airproducts.com/company/innovation/carbon-capture.*

[430] Department of Energy. (2011). Final Environmental Assessment for Air Products and Chemicals, Inc. Recovery Act: Demonstration of CO_2 Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large Scale Hydrogen Production. *https://netl.doe.gov/sites/default/files/environmental-assessments/20110622_APCI_PtA_CO2_FEA.pdf.*

[431] Department of Energy, Office of NEPA Policy and Compliance. (2013). EIS–0473: Record of Decision. *https://www.energy.gov/nepa/articles/eis-0473-record-decision.*

[432] Department of Energy. (2017). Petra Nova W.A. Parish Project. *https://www.energy.gov/fecm/petra-nova-wa-parish-project.*

[433] Kennedy, Greg. (2020). ''W.A. Parish Post Combustion CO_2 Capture and Sequestration Demonstration Project.'' Final Technical Report. *https://www.osti.gov/biblio/1608572/.*

[434] CEQ. (2021). ''Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration.'' *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

governance structure, set of procedures, and funding authorities to improve the Federal environmental review and authorization process for covered infrastructure projects.[435] The Utilizing Significant Emissions with Innovative Technologies (USE IT) Act, among other actions, clarified that CCS projects and CO_2 pipelines are eligible for this more predictable and transparent review process.[436] FAST–41 created the Federal Permitting Improvement Steering Council (Permitting Council), composed of agency Deputy Secretary-level members and chaired by an Executive Director appointed by the President. FAST–41 establishes procedures that standardize interagency consultation and coordination practices. FAST–41 codifies into law the use of the Permitting Dashboard [437] to track project timelines, including qualifying actions that must be taken by the EPA and other Federal agencies. Project sponsor participation in FAST–41 is voluntary.[438]

Community engagement also plays a role in the safe operation and construction of CO_2 pipelines. These efforts can be supported using the CCS Pipeline Route Planning Database that was developed by NETL, a public resource designed to support pipeline routing decisions and increase transportation safety.[439] The database includes state-specific regulations and restrictions, energy and social justice factors, land use requirements, existing infrastructure, and areas of potential risk. The database produces weighted values ranging from zero to one, where zero represents acceptable areas for pipeline placement and one represents areas that should be avoided.[440] The database will be a key input for the CCS Pipeline Route Planning Tool under development by NETL.[441] The purpose of the siting tool is to aid pipeline routing decisions and facilitate avoidance of areas that would pose permitting challenges.

In sum, the permitting process for CO_2 pipelines often involves private, local, state, tribal, and/or Federal agencies, and permitting timelines may vary depending on site characteristics. Projects that opt in to the FAST–41 process are eligible for a more transparent and predictable review process. EGUs can generally proceed to obtain permits and rights-of-way simultaneously, and the EPA anticipates that, in total, the permitting process would only take around 2.5 years for pipelines that only need an EA, with a possible additional year if the project requires an EIS (see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional information). This is consistent with the anticipated timelines for CCS discussed in section VII.C.1.a.i(E). Furthermore, the EPA notes that there is over 60 years of experience in the CO_2 pipeline industry designing, permitting, building and operating CO_2 pipelines, and that this expertise can be applied to the CO_2 pipelines that would be constructed to connect to sequestration sites and units.

As discussed above in section VII.C.1.a.i.(C)(1)(a), the core of the EPA's analysis of pipeline feasibility focuses on units located within 100 km (62 miles) of potential deep saline sequestration formations. The EPA notes that the majority (80 percent) of the coal-fired steam generating capacity with planned operation during or after 2039 is located within 100 km (62 miles) of the nearest potential deep saline sequestration site. For these sources, as explained, units would be required only to build relatively short pipelines, and such buildout would be feasible within the required timeframe. For the capacity that is more than 100 km (62 miles) away from sequestration, building a pipeline may become more complex. Almost all (98 percent) of this capacity's closest sequestration site is located outside state boundaries, and access to the nearest sequestration site would require building an interstate pipeline and coordinating with multiple state authorities for permitting purposes. Conversely, for capacity where the distance to the nearest potential sequestration site is less than 100 km (62 miles), only about 19 percent would require the associated pipeline to cross state boundaries. Therefore, the EPA believes that distance to the nearest sequestration site is a useful proxy for considerations related to the complexity of pipeline construction and how long it will take to build a pipeline.

A unit that is located more than 100 km away from sequestration may face complexities in pipeline construction, including additional permitting hurdles, difficulties in obtaining the necessary rights of way over such a distance, or other considerations, that may make it unreasonable for that unit to meet the compliance schedule that is generally reasonable for sources in the subcategory as a whole. Pursuant to the RULOF provisions of 40 CFR 60.2a(e)–(h), if a state can demonstrate that there is a fundamental difference between the information relevant to a particular affected EGU and the information the EPA considered in determining the compliance deadline for sources in the long-term subcategory, and that this difference makes it unreasonable for the EGU to meet the compliance deadline, a longer compliance schedule may be warranted. The EPA does not believe that the fact that a pipeline crosses state boundaries standing alone is sufficient to show that an extended timeframe would be appropriate—many such pipelines could be reasonably accomplished in the required timeframe. Rather, it is the confluence of factors, including that a pipeline crosses state boundaries, along with others that may make RULOF appropriate.

(3) Security of CO_2 Transport

As part of its analysis, the EPA also considered the safety of CO_2 pipelines. The safety of existing and new CO_2 pipelines that transport CO_2 in a supercritical state is regulated by PHMSA. These regulations include standards related to pipeline design, pipeline construction and testing, pipeline operations and maintenance, operator reporting requirements, operator qualifications, corrosion control and pipeline integrity management, incident reporting and response, and public awareness and communications. PHMSA has regulatory authority to conduct inspections of supercritical CO_2 pipeline operations and issue notices to operators in the event of operator noncompliance with regulatory requirements.[442]

CO_2 pipelines have been operating safely for more than 60 years. In the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines with zero incidents involving fatalities.[443] PHMSA reported a total of

[435] Federal Permitting Improvement Steering Council. (2022). FAST–41 Fact Sheet. *https://www.permits.performance.gov/documentation/fast-41-fact-sheet.*

[436] Galford, Chris. USE IT carbon capture bill becomes law, incentivizing development and deployment. (2020). *https://dailyenergyinsider.com/news/28522-use-it-carbon-capture-bill-becomes-law-incentivizing-development-and-deployment/.*

[437] Permitting Dashboard Federal Infrastructure Projects. *https://permits.performance.gov/.*

[438] EPA. ''FAST–41 Coordination.'' (2023). *https://www.epa.gov/sustainability/fast-41-coordination.*

[439] ''CCS Pipeline Route Planning Database V1—EDX.'' *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[440] ''CCS Pipeline Route Planning Database V1—EDX.'' *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[441] Department of Energy. ''CCS Pipeline Route Planning Database V1—EDX.'' *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1.*

[442] See generally 49 CFR 190–199.

[443] Congressional Research Service. 2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June

102 CO_2 pipeline incidents between 2003 and 2022, with one injury (requiring in-patient hospitalization) and zero fatalities.[444]

As noted previously in this preamble, a significant CO_2 pipeline rupture occurred in 2020 in Satartia, Mississippi, following heavy rains that resulted in a landslide. Although no one required in-patient hospitalization as a result of this incident, 45 people received treatment at local emergency rooms after the incident and 200 hundred residents were evacuated. Typically, when CO_2 is released into the open air, it vaporizes into a heavier-than-air gas and dissipates. During the Satartia incident, however, unique atmospheric conditions and the topographical features of the area delayed this dissipation. As a result, residents were exposed to high concentrations of CO_2 in the air after the rupture. Furthermore, local emergency responders were not informed by the operator of the rupture and the nature of the unique safety risks of the CO_2 pipeline.[445]

PHMSA initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of supercritical CO_2 pipelines following the investigation into the CO_2 pipeline failure in Satartia.[446] PHMSA submitted the associated Notice of Proposed Rulemaking to the White House Office of Management and Budget on February 1, 2024 for pre-publication review.[447] Following the Satartia incident, PHMSA also issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice) to the operator related to probable violations of Federal pipeline safety regulations. The Notice was ultimately resolved through a Consent Agreement between PHMSA and the operator that includes the assessment of civil penalties and identifies actions for the operator to take to address the alleged violations and risk conditions.[448] PHMSA has further issued an updated nationwide advisory bulletin to all pipeline operators and solicited research proposals to strengthen CO_2 pipeline safety.[449] Given the Federal and state regulation of CO_2 pipelines and the steps that PHMSA is taking to further improve pipeline safety, the EPA believes CO_2 can be safely transported by pipeline.

Certain states have authority delegated from the U.S. Department of Transportation to conduct safety inspections and enforce state and Federal pipeline safety regulations for intrastate CO_2 pipelines.[450] [451] [452] PHMSA's state partners employ about 70 percent of all pipeline inspectors, which covers more than 80 percent of regulated pipelines.[453] Federal law requires certified state authorities to adopt safety standards at least as stringent as the Federal standards.[454] Further, there are required steps that CO_2 pipeline operators must take to ensure pipelines are operated safely under PHMSA standards and related state standards, such as the use of pressure monitors to detect leaks or initiate shut-off valves, and annual reporting on operations, structural integrity assessments, and inspections.[455] These CO_2 pipeline controls and PHMSA standards are designed to ensure that captured CO_2 will be securely conveyed to a sequestration site.

(4) Comments Received on CO_2 Transport and Responses

The EPA received comments on CO_2 transport, including CO_2 pipelines. Those comments, and the EPA's responses, are as follows.

Comment: Some commenters identified challenges to the deployment of a national, interstate CO_2 pipeline network. In particular, those commenters discussed the experience faced by long (*e.g.,* over 1,000 miles) CO_2 pipelines seeking permitting and right-of-way access in Midwest states including Iowa and North Dakota. Commenters claimed those challenges make CCS as BSER infeasible. Some commenters argued that the existing CO_2 pipeline capacity is not adequate to meet potential demand caused by this rule and that the ability of the network to grow and meet future potential demand is hindered by significant public opposition.

Response: The EPA acknowledges the challenges that some large multi-state pipeline projects have faced, but does not agree that those experiences show that the BSER is not adequately demonstrated or that the standards finalized in these actions are not achievable. As detailed in the preceding subsections of the preamble, the BSER is not premised on the buildout of a national, trunkline CO_2 pipeline network. Most coal-fired steam generating units are in relatively close proximity to geologic storage, and those shorter pipelines would not likely be as challenging to permit and build as demonstrated by the examples of smaller pipeline discussed above.

The EPA acknowledges that some larger trunkline CO_2 pipeline projects, specifically the Heartland Greenway project, have recently been delayed or canceled. However, many projects are still moving forward and several major projects have recently been announced to expand the CO_2 pipeline network across the United States. The EPA notes that there are often opportunities to reroute pipelines to minimize permitting challenges and landowner concerns. For example, Summit Carbon Solutions changed their planned pipeline route in North Dakota after their initial permit was denied, leading to successful acquisition of rights of way.[456] Additionally, Tallgrass, which

3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[444] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[445] Failure Investigation Report—Denbury Gulf Coast Pipeline, May 2022. *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf.*

[446] PHMSA. (2022). ''PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak.'' *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

[447] Columbia Law School. (2024). PHMSA Advances CO2 Pipeline Safety Regulations. *https://climate.law.columbia.edu/content/phmsa-advances-co2-pipeline-safety-regulations.*

[448] Department of Transportation. (2023). Consent Order, Denbury Gulf Coast Pipelines, LLC, CPF No. 4–2022–017–NOPV *https://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_42022017NOPV.html?nocache=7208.*

[449] Ibid.

[450] New Mexico Public Regulation Commission. 2023. Transportation Pipeline Safety. New Mexico Public Regulation Commission, Bureau of Pipeline Safety. *https://www.nm-prc.org/transportation/pipeline-safety.*

[451] Texas Railroad Commission. 2023. *Oversight & Safety Division.* Texas Railroad Commission. *https://www.rrc.texas.gov/about-us/organization-and-activities/rrc-divisions/oversight-safety-division.*

[452] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[453] PHMSA. (2023). ''PHMSA Issues Letters to Wolf Carbon, Summit, and Navigator Clarifying Federal, State, and Local Government Pipeline Authorities.'' *https://www.phmsa.dot.gov/news/phmsa-issues-letters-wolf-carbon-summit-and-navigator-clarifying-federal-state-and-local.*

[454] PHMSA, ''PHMSA Issues Letters to Wolf Carbon, Summit, and Navigator Clarifying Federal, State, and Local Government Pipeline Authorities.'' 2023. *https://www.phmsa.dot.gov/news/phmsa-issues-letters-wolf-carbon-summit-and-navigator-clarifying-federal-state-and-local.*

[455] Carbon Capture Coalition. ''PHMSA/Pipeline Safety Fact Sheet,'' November 2023. *https://carboncapturecoalition.org/wp-content/uploads/2023/11/Pipeline-Safety-Fact-Sheet.pdf.*

[456] Summit Carbon Solutions. Summit Carbon Solutions Signs 80 Percent of North Dakota

Continued

is planning to convert a 630 km (392 mile) natural gas pipeline to carry CO_2, announced that they had reach a community benefits agreement, in which certain organizations have agreed not to oppose the pipeline project while Tallgrass has agreed to terms such as contributing funds to first responders along the pipeline route and providing royalty checks to landowners.[457] See section VII.C.1.a.i(C)(1)(d) for additional discussion of planned CO_2 pipelines. While access to larger trunkline projects would not be required for most EGUs, at least some larger trunkline projects are likely to be constructed, which would increase opportunities for connecting to pipeline networks.

Comment: Some commenters disagreed with the modeling assumption that 100 km is a typical pipeline distance. The commenters asserted that there is data showing the actual locations of the power plants affected by the rule, and the required pipeline distance is not always 100 km.

Response: The EPA acknowledges that the physical locations of EGUs and the physical locations of carbon sequestration capacity and corresponding pipeline distance will not be 100 km in all cases. As discussed previously in section VII.C.1.a.i(C)(1)(a), the EPA modeled the unique approximate distance from each existing coal-fired steam generating capacity with planned operation during or after 2039 to the nearest potential saline sequestration site, and found that the majority (80 percent) is within 100 km (62 miles) of potential saline sequestration sites, and another 11 percent is within 160 km (100 miles).[458] Furthermore, the EPA disagrees with the comments suggesting that the use of 100 km is an inappropriate economic modeling assumption. The 100 km assumption was not meant to encompass the physical location of every potentially affected EGU. The 100 km assumption is intended as an economic modeling assumption and is based on similar assumptions applied in NETL studies used to estimate CO_2 transport costs. The EPA carefully reviewed the assumptions on which the NETL transport cost estimates are based and continues to find them reasonable. The NETL studies referenced in section VII.C.1.a.ii based transport costs on a generic 100 km (62 mile) pipeline and a generic 80 km pipeline.[459] For most EGUs, the necessary pipeline distance is anticipated to be less than 100 km and therefore the associated costs could also be lower than these assumptions. Other published economic models applying different assumptions have also reached the conclusion that CO_2 transport and sequestration are adequately demonstrated.[460]

Comment: Commenters also stated that the permitting and construction processes can be time-consuming.

Response: The EPA acknowledges building CO_2 pipelines requires capital expenditure and acknowledges that the timeline for siting, engineering design, permitting, and construction of CO_2 pipelines depends on factors including the pipeline capacity and pipeline length, whether the pipeline route is intrastate or interstate, and the specifics of the state pipeline regulator's regulatory requirements. In the BSER analysis, individual EGUs that are subject to carbon capture requirements are assumed to take a point-to-point approach to CO_2 transport and sequestration. These smaller-scale projects require less capital and may present less complexity than larger projects. The EPA considers the timeline to permit and install such pipelines in section VII.C.1.a.i(E) of the preamble, and has determined that a compliance date of January 1, 2032 allows for a sufficient amount of time.

Comment: Some commenters expressed significant concerns about the safety of CO_2 pipelines following the CO_2 pipeline failure in Satartia, Mississippi in 2020.

Response: For a discussion of the safety of CO_2 pipelines and the Satartia pipeline failure, see section VII.C.1.a.i(C)(3). The EPA believes that the framework of Federal and state regulation of CO_2 pipelines and the steps that PHMSA is taking to further improve pipeline safety, is sufficient to ensure CO_2 can be safely transported by pipeline.

(D) Geologic Sequestration of CO_2

The EPA is finalizing its determination that geologic sequestration (*i.e.,* the long-term containment of a CO_2 stream in subsurface geologic formations) is adequately demonstrated. In this section, we provide an overview of the availability of sequestration sites in the U.S., discuss how geologic sequestration of CO_2 is well proven and broadly available throughout the U.S, explain the effectiveness of sequestration, discuss the regulatory framework for UIC wells, and discuss the timing of permitting for sequestration sites. We then provide a summary of key comments received concerning geologic sequestration and our responses to those comments.

(1) Sequestration Sites for Coal-Fired Power Plants Subject to CCS Requirements

(a) Broad Availability of Sequestration

Sequestration is broadly available in the United States, which makes clear that it is adequately demonstrated. By far the most widely available and well understood type of sequestration is that in deep saline formations. These formations are common in the U.S. These formations are numerous and only a small subset of the existing saline storage capacity would be required to store the CO_2 from EGUs. Many projects are in the process of completing thorough subsurface studies of these deep saline formations to determine their suitability for regional-scale storage. Furthermore, sequestration formations could also include unmineable coal seams and oil and gas reservoirs. CO_2 may be stored in oil and gas reservoirs in association with EOR and enhanced gas recovery (EGR) technologies, collectively referred to as enhanced recovery (ER), which include the injection of CO_2 in oil and gas reservoirs to increase production. ER is a technology that has been used for decades in states across the U.S.[461]

Geologic sequestration is based on a demonstrated understanding of the trapping and containment processes that retain CO_2 in the subsurface. The presence of a low permeability seal is an important component of demonstrating secure geologic sequestration. Analyses of the potential availability of geologic sequestration capacity in the United States have been conducted by DOE,

Landowners. (2023). *https://summitcarbonsolutions.com/summit-carbon-solutions-signs-80-percent-of-north-dakota-landowners/.*

[457] Hammel, Paul. (2024). Pipeline company, Nebraska environmental group strike unique 'community benefits' agreement. *https://www.desmoinesregister.com/story/tech/science/environment/2024/04/11/nebraska-environmentalist-forge-peace-pact-with-pipeline-company/73282852007/.*

[458] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[459] The pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length.

[460] Ogland-Hand, Jonathan D. et. al. 2022. *Screening for Geologic Sequestration of CO_2: A Comparison Between SCO2TPRO and the FE/NETL CO_2 Saline Storage Cost Model.* International Journal of Greenhouse Gas Control, Volume 114, February 2022, 103557. *https://www.sciencedirect.com/science/article/pii/S175058362100308X.*

[461] NETL. (2010). Carbon Dioxide Enhanced Oil Recovery. *https://www.netl.doe.gov/sites/default/files/netl-file/co2_eor_primer.pdf.*

and the U.S. Geological Survey (USGS) has also undertaken a comprehensive assessment of geologic sequestration resources in the United States.[462] [463] Geologic sequestration potential for CO_2 is widespread and available throughout the United States. Nearly every state in the United States has or is in close proximity to formations with geologic sequestration potential, including areas offshore. There have been numerous efforts demonstrating successful geologic sequestration projects in the United States and overseas, and the United States has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. Moreover, the amount of storage potential can readily accommodate the amount of CO_2 for which sequestration could be expected under this final rule.

The EPA has performed a geographic availability analysis in which the Agency examined areas of the U.S. with sequestration potential in deep saline formations, unmineable coal seams, and oil and gas reservoirs; information on existing and probable, planned or under study CO_2 pipelines; and areas within a 100 km (62-mile) area of potential sequestration sites. This availability analysis is based on resources from the DOE, the USGS, and the EPA. The distance of 100 km is consistent with the assumptions underlying the NETL cost estimates for transporting CO_2 by pipeline. The scoping assessment by the EPA found that at least 37 states have geologic characteristics that are amenable to deep saline sequestration, and an additional 6 states are within 100 kilometers of potentially amenable deep saline formations in either onshore or offshore locations. Of the 7 states that are further than 100 km (62 mi) of onshore or offshore storage potential in deep saline formations, only New Hampshire has coal EGUs that were assumed to be in operation after 2039, with a total capacity of 534 MW. However, the EPA notes that as of March 27, 2024, the last coal-fired steam EGUs in New Hampshire announced that they would cease operation by 2028.[464] Therefore, the EPA anticipates that there will no existing coal-fired steam EGUs located in states that are further than 100 km (62 mi) of potential geologic sequestration sites. Furthermore, as described in section VII.C.1.a.i(C), new EGUs would have the ability to consider proximity and access to geologic sequestration sites or CO_2 pipelines in the siting process.

The DOE and the United States Geological Survey (USGS) have independently conducted preliminary analyses of the availability and potential CO_2 sequestration resources in the United States. The DOE estimates are compiled in the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB) using volumetric models and are published in its Carbon Utilization and Sequestration Atlas (NETL Atlas). The DOE estimates that areas of the United States with appropriate geology have a sequestration potential of at least 2,400 billion to over 21,000 billion metric tons of CO_2 in deep saline formations, unmineable coal seams, and oil and gas reservoirs. The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 sequestration potential across the United States. With respect to deep saline formations, the DOE estimates a sequestration potential of at least 2,200 billion metric tons of CO_2 in these formations in the United States. The EPA estimates that the CO_2 emissions reductions for this rule (which is similar to the amount of CO_2 may be sequestered under this rule) are estimated in the range of 1.3 to 1.4 billion metric tons over the 2028 to 2047 timeframe.[465] This volume of sequestered CO_2 is less than a tenth of a percent of the storage capacity in deep saline formations estimated to be available by DOE.

Unmineable coal seams offer another potential option for geologic sequestration of CO_2. Enhanced coalbed methane recovery is the process of injecting and storing CO_2 in unmineable coal seams to enhance methane recovery. These operations take advantage of the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. When CO_2 is injected, it is adsorbed to the coal surface and releases methane that can then be captured and produced. This process effectively ''locks'' the CO_2 to the coal, where it remains stored. States with the potential for sequestration in unmineable coal seams include Iowa and Missouri, which have little to no saline sequestration potential and have existing coal-fired EGUs. Unmineable coal seams have a sequestration potential of at least 54 billion metric tons of CO_2, or 2 percent of total potential in the United States, and are located in 22 states.

The potential for CO_2 sequestration in unmineable coal seams has been demonstrated in small-scale demonstration projects, including the Allison Unit pilot project in New Mexico, which injected a total of 270,000 tons of CO_2 over a 6-year period (1995–2001). Further, DOE Regional Carbon Sequestration Partnership projects have injected CO_2 volumes in unmineable coal seams ranging from 90 tons to 16,700 tons, and completed site characterization, injection, and post-injection monitoring for sites. DOE has included unmineable coal seams in the NETL Atlas. One study estimated that in the United States, 86.16 billion tons of CO_2 could be permanently stored in unmineable coal seams.[466] Although the large-scale injection of CO_2 in coal seams can lead to swelling of coal, the literature also suggests that there are available technologies and techniques to compensate for the resulting reduction in injectivity. Further, the reduced injectivity can be anticipated and accommodated in sizing and characterizing prospective sequestration sites.

Depleted oil and gas reservoirs present additional potential for geologic sequestration. The reservoir characteristics of developed fields are well known as a result of exploration and many years of hydrocarbon production and, in many areas, infrastructure already exists which could be evaluated for conversion to CO_2 transportation and sequestration service. Other types of geologic formations such as organic rich shale and basalt may also have the ability to store CO_2, and DOE is continuing to evaluate their potential sequestration capacity and efficacy.

(b) Inventory of Coal-Fired Power Plants That Are Candidates for CCS

Sequestration potential as it relates to distance from existing coal-fired steam generating units is a key part of the EPA's regular power sector modeling, using data from DOE/NETL studies.[467] As discussed in section VII.C.1.a.i(D)(1)(a), the availability

[462] U.S. DOE NETL. (2015). Carbon Storage Atlas, Fifth Edition, September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.*

[463] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). National assessment of geologic carbon dioxide storage resources—Summary: U.S. Geological Survey Factsheet 2013–3020. *http://pubs.usgs.gov/fs/2013/3020/.*

[464] Vickers, Clayton. (2024). ''Last coal plants in New England to close; renewables take their place.'' *https://thehill.com/policy/energy-environment/4560375-new-hampshire-coal-plants-closing/.*

[465] For detailed information on the estimated emissions reductions from this rule, see section 3 of the RIA, available in the rulemaking docket.

[466] Godec, Koperna, and Gale. (2014). ''CO_2-ECBM: A Review of its Status and Global Potential'', Energy Procedia, Volume 63. *https://doi.org/10.1016/j.egypro.2014.11.619.*

[467] For details, please see Chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

analysis shows that of the coal-fired steam generating capacity with planned operation during or after 2039, more than 50 percent is less than 32 km (20 miles) from potential deep saline sequestration sites, 73 percent is located within 50 km (31 miles), 80 percent is located within 100 km (62 miles), and 91 percent is within 160 km (100 miles).[468]

(2) Geologic Sequestration of CO_2 Is Adequately Demonstrated

Geologic sequestration is based on a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. Existing project and regulatory experience, along with other information, indicate that geologic sequestration is a viable long-term CO_2 sequestration option. As discussed in this section, there are many examples of projects successfully injecting and containing CO_2 in the subsurface.

Research conducted through the Department of Energy's Regional Carbon Sequestration Partnerships has demonstrated geologic sequestration through a series of field research projects that increased in scale over time, injecting more than 12 million tons of CO_2 with no indications of negative impacts to either human health or the environment.[469] Building on this experience, DOE launched the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative in 2016 to demonstrate how knowledge from the Regional Carbon Sequestration Partnerships can be applied to commercial-scale safe storage. This initiative is furthering the development and refinement of technologies and techniques critical to the characterization of sites with the potential to sequester greater than 50 million tons of CO_2.[470] In Phase I of CarbonSAFE, thirteen projects conducted economic feasibility analyses, collected, analyzed, and modeled extensive regional data, evaluated multiple storage sites and infrastructure, and evaluated business plans. Six projects were funded for Phase II which involves storage complex feasibility studies. These projects evaluate initial reservoir characteristics to determine if the reservoir is suitable for geologic sequestration sites of more than 50 million tons of CO_2, address technical and non-technical challenges that may arise, develop a risk assessment and CO_2 management strategy for the project; and assist with the validation of existing tools. Five projects have been funded for CarbonSAFE Phase III and are currently performing site characterization and permitting.

The EPA notes that, while only sequestration facilities with Federal funding are currently operational in the United States, multiple commercial sequestration facilities, other than those funded under EPAct05, are in construction or advanced development, with some scheduled to open for operation as early as 2025.[471] These facilities have proposed sequestration capacities ranging from 0.03 to 6 million tons of CO_2 per year. The Great Plains Synfuel Plant currently captures 2 million metric tons of CO_2 per year, which is exported to Canada for use in EOR; a planned addition of sequestration in a saline formation for this facility is expected to increase the amount of CO_2 captured and sequestered (through both geologic sequestration and EOR) to 3.5 million metric tons of CO_2 per year.[472] The EPA and states with approved UIC Class VI programs (including Wyoming, North Dakota, and Louisiana) are currently reviewing UIC Class VI geologic sequestration well permit applications for proposed sequestration sites in fourteen states.[473] [474] [475] As of March 15, 2024, 44 projects with 130 injection wells are under review by the EPA.[476]

Currently, there are planned geologic sequestration facilities across the United States in various phases of development, construction, and operation. The Wyoming Department of Environmental Quality issued three UIC Class VI permits in December 2023 to Frontier Carbon Solutions. The Frontier Carbon Solutions project will sequester 5 million metric tons of CO_2/year.[477] Additionally, UIC Class VI permit applications have been submitted to the Wyoming Department of Environmental Quality for a proposed Eastern Wyoming Sequestration Hub project that would sequester up to 3 million metric tons of CO_2/year.[478] The North Dakota Oil and Gas Division has issued UIC Class VI permits to 6 sequestration projects that collectively will sequester 18 million metric tons of CO_2/year.[479] Since 2014, the EPA has issued two UIC Class VI permits to Archer Daniels Midland (ADM) in Decatur, Illinois, which authorize the injection of up to 7 million metric tons of CO_2. One of the AMD wells is in the injection phase while the other is in the post-injection phase. In January 2024, the EPA issued two UIC Class VI permits to Wabash Carbon Services LLC for a project that will sequester up to 1.67 million metric tons of CO_2/year over an injection period of 12 years.[480] In December 2023, the EPA released for public comment four UIC Class VI draft permits for the Carbon TerraVault projects, to be located in California.[481] These projects propose to sequester CO_2 captured from multiple different sources in California including a hydrogen plant, direct air capture, and pre-combustion gas treatment. TerraVault plans to inject 1.46 million metric tons of CO_2 annually into the four proposed wells over a 26-year injection period with a total potential capacity of 191 million metric tons.[482] [483] One of the proposed wells is

[468] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf.*

[469] Regional Sequestration Partnership Overview. *https://netl.doe.gov/carbon-management/carbon-storage/RCSP.*

[470] National Energy Technology Laboratory. CarbonSAFE Initiative. *https://netl.doe.gov/carbon-management/carbon-storage/carbonsafe.*

[471] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[472] Basin Electric Power Cooperative. (2021). ''Great Plains Synfuels Plant Potential to Be Largest Coal-Based Carbon Capture and Storage Project to Use Geologic Storage''. *https://www.basinelectric.com/News-Center/news-releases/Great-Plains-Synfuels-Plant-potential-to-be-largest-coal-based-carbon-capture-and-storage-project-to-use-geologic-storage.*

[473] UIC regulations for Class VI wells authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water. The major components to be included in UIC Class VI permits are detailed further in section VII.C.1.a.i(D)(4).

[474] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 25, 2024. *https://www.epa.gov/uic/table-epas-draft-and-final-class-vi-well-permits* Last updated January 19, 2024.

[475] U.S. EPA Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[476] U.S. EPA. Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[477] Wyoming DEQ, Water Quality. Wyoming grants its first three Class VI permits. By Kimberly Mazza, December 14, 2023 *https://deq.wyoming.gov/2023/12/wyoming-grants-its-first-three-class-vi-permits/.*

[478] Wyoming DEQ Class VI Permit Applications. Trailblazer permit application. *https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi.*

[479] North Dakota Oil and Gas Division, Class VI—Geologic Sequestration Wells. *https://www.dmr.nd.gov/dmr/oilgas/ClassVI.*

[480] EPA Approves Permits to Begin Construction of Wabash Carbon Services Underground Injection Wells in Indiana's Vermillion and Vigo Counties. (2024) *https://www.epa.gov/uic/epa-approves-permits-wabash-carbon-services-underground-injection-wells-indianas-vigo-and*

[481] U.S. EPA Current Class VI Projects under Review at EPA. 2024. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[482] U.S. EPA Class VI Permit Application. ''Intent to Issue Four (4) Class VI Geologic Carbon Sequestration Underground Injection Control (UIC)

an existing UIC Class II well that would be converted to a UIC Class VI well for the TerraVault project.[484]

Geologic sequestration has been proven to be successful and safe in projects internationally. In Norway, facilities conduct offshore sequestration under the Norwegian continental shelf.[485] In addition, the Sleipner CO_2 Storage facility in the North Sea, which began operations in 1996, injects around 1 million metric tons of CO_2 per year from natural gas processing.[486] The Snohvit CO_2 Storage facility in the Barents Sea, which began operations in 2008, injects around 0.7 million metric tons of CO_2 per year from natural gas processing. The SaskPower carbon capture and sequestration facility at Boundary Dam Power Station in Saskatchewan, Canada had, as of the end of 2023, captured 5.6 million metric tons of CO_2 since it began operating in 2014.[487] Other international sequestration facilities in operation include Glacier Gas Plant MCCS (Canada),[488] Quest (Canada), and Qatar LNG CCS (Qatar). The CarbFix project in Iceland injects CO_2 into a geologic formation in which the CO_2 reacts with basalt rock formations to form stone. The CarbFix project has injected approximately 100,000 metric tons of CO_2 into geologic formations since 2014.[489]

EOR, the process of injecting CO_2 into oil and gas formations to extract additional oil and gas, has been successfully used for decades at numerous production fields throughout the United States to increase oil and gas recovery. The oil and gas industry in the United States has nearly 60 years of experience with EOR.[490] This experience provides a strong foundation for demonstrating successful CO_2 injection and monitoring technologies, which are needed for safe and secure geologic sequestration that can be used for deployment of CCS across geographically diverse areas. The amount of CO_2 that can be injected for an EOR project and the duration of operations are of similar magnitude to the duration and volume of CO_2 that is expected to be captured from fossil fuel-fired EGUs. The Farnsworth Unit, the Camrick Unit, the Shute Creek Facility, and the Core Energy CO_2-EOR facility are all examples of operations that store anthropogenic CO_2 as a part of EOR operations.[491] [492] Currently, 13 states have active EOR operations, and these states also have areas that are amenable to deep saline sequestration in either onshore or offshore locations.[493]

(3) EPAct05-Assisted Geologic Sequestration Projects

Consistent with the EPA's legal interpretation that the Agency can rely on experience from EPAct05 funded facilities in conjunction with other information, this section provides examples of EPAct05-assisted geologic sequestration projects. While the EPA has determined that the sequestration component of CCS is adequately demonstrated based on the non-EPAct05 examples discussed above, adequate demonstration of geologic sequestration is further corroborated by planned and operational geologic sequestration projects assisted by grants, loan guarantees, and the IRC section 48A federal tax credit for ''clean coal technology'' authorized by the EPAct05.[494]

At present, there are 13 operational and one post-injection phase commercial carbon sequestration facilities in the United States.[495] [496] Red Trail Energy CCS Project in North Dakota and Illinois Industrial Carbon Capture and Storage in Illinois are dedicated saline sequestration facilities, while the other facilities, including Petra Nova in Texas, are sequestration via EOR.[497] [498] Several other facilities are under development.[499] The Red Trail Energy CCS facility in North Dakota began injecting CO_2 captured from ethanol production plants in 2022.[500] This project is expected to inject 180,000 tons of CO_2 per year.[501] The Illinois Industrial Carbon Capture and Storage Project began injecting CO_2 from ethanol production into the Mount Simon Sandstone in April 2017. According to the facility's report to the EPA's Greenhouse Gas Reporting Program (GHGRP), as of 2022, 2.9 million metric tons of CO_2 had been injected into the saline reservoir.[502] CO_2 injection for one of the two permitted Class VI wells ceased in 2021 and this well is now in the post-operation data collection phase.[503]

There are additional planned geologic sequestration projects under review by the EPA and across the United States.[504] [505] Project Tundra, a saline sequestration project planned at the lignite-fired Milton R. Young Station in North Dakota is projected to capture 4 million metric tons of CO_2 annually.[506] In Wyoming, Class VI permit

Permits for Carbon TerraVault JV Storage Company Sub 1, LLC. EPA–R09–OW–2023–0623.'' *https://www.epa.gov/publicnotices/intent-issue-class-vi-underground-injection-control-permits-carbon-terravault-jv.*

[483] California Resources Corporation. ''Carbon TerraVault Potential Storage Capacity.''*https://www.crc.com/carbon-terravault/Vaults/default.aspx.*

[484] U.S. EPA Class VI Permit Application. ''Intent to Issue Four (4) Class VI Geologic Carbon Sequestration Underground Injection Control (UIC) Permits for Carbon TerraVault JV Storage Company Sub 1, LLC. EPA–R09–OW–2023–0623.

[485] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage. *https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/.*

[486] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[487] BD3 Status Update: Q3 2023. *https://www.saskpower.com/about-us/our-company/blog/2023/bd3-status-update-q3-2023.*

[488] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[489] CarbFix Operations. (2024). *https://www.carbfix.com/.*

[490] NETL. (2010). Carbon Dioxide Enhanced Oil Recovery. *https://www.netl.doe.gov/sites/default/files/netl-file/co2_eor_primer.pdf.*

[491] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[492] Greenhouse Gas Reporting Program monitoring reports for these facilities are available at *https://www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide#decisions.*

[493] U.S. DOE NETL, Carbon Storage Atlas, Fifth Edition, September 2015. *https://www.netl.doe.gov/research/coal/carbon-storage/atlasv.*

[494] 80 FR 64541–42 (October 23, 2015).

[495] Clean Air Task Force. (August 3, 2023). U.S. Carbon Capture Activity and Project Map. *https://www.catf.us/ccsmapus/.*

[496] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[497] Reuters. (September 14, 2023) ''Carbon capture project back at Texas coal plant after 3-year shutdown''. *https://www.reuters.com/business/energy/carbon-capture-project-back-texas-coal-plant-after-3-year-shutdown-2023-09-14/.*

[498] Clean Air Task Force. (August 3, 2023). U.S. Carbon Capture Activity and Project Map. *https://www.catf.us/ccsmapus/.*

[499] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[500] Ibid.

[501] Ibid.

[502] EPA Greenhouse Gas Reporting Program. Data reported as of August 12, 2022.

[503] University of Illinois Urbana-Champaign, Prairie Research Institute. (2022). Data from landmark Illinois Basin carbon storage project are now available. *https://blogs.illinois.edu/view/7447/54118905.*

[504] In addition, Denbury Resources injected CO_2 into a depleted oil and gas reservoir at a rate greater than 1.2 million tons/year as part of a DOE Southeast Regional Carbon Sequestration Partnership study. The Texas Bureau of Economic Geology tested a wide range of surface and subsurface monitoring tools and approaches to document sequestration efficiency and sequestration permanence at the Cranfield oilfield in Mississippi. Texas Bureau of Economic Geology, ''Cranfield Log.'' *https://www.beg.utexas.edu/gccc/research/cranfield.*

[505] EPA Class VI Permit Tracker. *https://www.epa.gov/system/files/documents/2024-02/class-vi-permit-tracker_2-5-24.pdf.* Accessed February 5, 2024.

[506] Project Tundra. ''Project Tundra.'' *https://www.projecttundrand.com/.*

applications have been issued by the Wyoming Department of Environmental Quality for the proposed Eastern Wyoming Sequestration Hub project, a saline sequestration facility proposed to be located in Southwestern Wyoming.[507] At full capacity, the facility would permanently store up to 5 million metric tons of CO_2 captured from industrial facilities annually in the Nugget saline sandstone reservoir.[508] In Texas, three NGCCs plan to add carbon capture equipment. Deer Park NGCC plans to capture 5 million tons per year, Quail Run NGCC plans to capture 1.5 million tons of CO_2 per year, and Baytown NGCC plans to capture up to 2 million tons of CO_2 per year.[509] [510]

(4) Security of Geologic Sequestration and Related Regulatory Requirements

As discussed in section VII.C.1.a.i(D)(2) of this preamble, there have been numerous instances of geologic sequestration in the U.S. and overseas, and the U.S. has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. This regulatory framework includes the UIC well regulations pursuant to SDWA authority, and the GHGRP pursuant to CAA authority.

Regulatory oversight of geologic sequestration is built upon an understanding of the proven mechanisms by which CO_2 is retained in geologic formations. These mechanisms include (1) Structural and stratigraphic trapping (generally trapping below a low permeability confining layer); (2) residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the geologic formation); (3) solubility trapping (dissolution in the in situ formation fluids); (4) mineral trapping (reaction with the minerals in the geologic formation and confining layer to produce carbonate minerals); and (5) preferential adsorption trapping (adsorption onto organic matter in coal and shale).

(a) Overview of Legal and Regulatory Framework

For the reasons detailed below, the UIC Program, the GHGRP, and other regulatory requirements comprise a detailed regulatory framework for geologic sequestration in the United States. This framework is analyzed in a 2021 report from the Council on Environmental Quality (CEQ),[511] and statutory and regulatory frameworks that may be applicable for CCS are summarized in the EPA CCS Regulations Table.[512] [513] This regulatory framework includes the UIC regulations, promulgated by the EPA under the authority of the Safe Drinking Water Act (SDWA); and the GHGRP, promulgated by the EPA under the authority of the CAA. The requirements of the UIC and GHGRP programs work together to ensure that sequestered CO_2 will remain securely stored underground. Furthermore, geologic sequestration efforts on Federal lands as well as those efforts that are directly supported with Federal funds would need to comply with the NEPA and other Federal laws and regulations, depending on the nature of the project.[514] In cases where sequestration is conducted offshore, the SDWA, the Marine Protection, Research, and Sanctuaries Act (MPRSA) or the Outer Continental Shelf Lands Act (OCSLA) may apply. The Department of Interior Bureau of Safety and Environmental Enforcement and Bureau of Ocean Energy Management are developing new regulations and creating a program for oversight of carbon sequestration activities on the outer continental shelf.[515] Furthermore, Title V of the Federal Land Policy and Management Act of 1976 (FLPMA) and its implementing regulations, 43 CFR part 2800, authorize the Bureau of Land Management (BLM) to issue rights-of-way (ROWs) to geologically sequester CO_2 in Federal pore space, including BLM ROWs for the necessary physical infrastructure and for the use and occupancy of the pore space itself. The BLM has published a policy defining access to pore space on BLM lands, including clarification of Federal policy for situations where the surface and pore space are under the control of different Federal agencies.[516]

(b) Underground Injection Control (UIC) Program

The UIC regulations, including the Class VI program, authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water (USDW). These regulations are built upon nearly a half-century of Federal experience regulating underground injection wells, and many additional years of state UIC program expertise. The IIJA established a $50 million grant program to assist states and tribal regulatory authorities in developing and implementing UIC Class VI programs.[517] Major components included in UIC Class VI permits are site characterization, area of review,[518] corrective action,[519] well construction and operation, testing and monitoring, financial responsibility, post-injection site care, well plugging, emergency and remedial response, and site closure. The EPA's UIC regulations are included in 40 CFR parts 144–147. The UIC regulations ensure that injected CO_2 does not migrate out of the authorized injection zone, which in turn ensures that CO_2 is securely stored underground.

Review of a UIC permit application by the permitting authority, including for Class VI geologic sequestration, entails a multidisciplinary evaluation to determine whether the application includes the required information, is technically accurate, and supports a determination that USDWs will not be endangered by the proposed injection

[507] Wyoming DEQ Class VI Permit Applications. *https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/*.

[508] *Id.*

[509] Calpine. (2023). Calpine Carbon Capture, Bayton, Texas. *https://calpinecarboncapture.com/wp-content/uploads/2023/04/Calpine-Baytown-One-Pager-English-1.pdf.*

[510] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[511] CEQ. (2021). ''Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration.'' *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[512] EPA. 2023. Regulatory and Statutory Authorities Relevant to Carbon Capture and Sequestration (CCS) Projects. *https://www.epa.gov/system/files/documents/2023-10/regulatory-and-statutory-authorities-relevant-to-carbon-capture-and-sequestration-ccs-projects.pdf.*

[513] This table serves as a reference of many possible authorities that may affect a CCS project (including site selection, capture, transportation, and sequestration). Many of the authorities listed in this table would apply only in specific circumstances.

[514] CEQ. ''Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration.'' 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[515] Department of the Interior. (2023). BSEE Budget. *https://www.doi.gov/ocl/bsee-budget.*

[516] National Policy for the Right-of-Way Authorizations Necessary for Site Characterization, Capture, Transportation, Injection, and Permanent Geologic Sequestration of Carbon Dioxide in Connection with Carbon Sequestration Projects. BLM IM 2022–041 Instruction Memorandum, June 8, 2022. *https://www.blm.gov/policy/im-2022-041.*

[517] EPA. Underground Injection Control Class VI Wells Memorandum. (December 9, 2022). *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[518] Per 40 CFR 146.84(a), the area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

[519] UIC permitting authorities may require corrective action for existing wells within the area of review to ensure protection of underground sources of drinking water.

activity.[520] The EPA promulgated UIC regulations to ensure underground injection wells are constructed, operated, and closed in a manner that is protective of USDWs and to address potential risks to USDWs associated with injection activities.[521] The UIC regulations address the major pathways by which injected fluids can migrate into USDWs, including along the injection well bore, via improperly completed or plugged wells in the area near the injection well, direct injection into a USDW, faults or fractures in the confining strata, or lateral displacement into hydraulically connected USDWs. States may apply to the EPA to be the UIC permitting authority in the state and receive primary enforcement authority (primacy). Where a state has not obtained primacy, the EPA is the UIC permitting authority.

Recognizing that CO_2 injection, for the purpose of geologic sequestration, poses unique risks relative to other injection activities, the EPA promulgated Federal Requirements Under the UIC Program for Carbon Dioxide GS Wells, known as the Class VI Rule, in December 2010.[522] The Class VI Rule created and set requirements for a new class of injection wells, Class VI. The Class VI Rule builds upon the long-standing protective framework of the UIC Program, with requirements that are tailored to address issues unique to large-scale geologic sequestration, including large injection volumes, higher reservoir pressures relative to other injection formations, the relative buoyancy of CO_2, the potential presence of impurities in captured CO_2, the corrosivity of CO_2 in the presence of water, and the mobility of CO_2 within subsurface geologic formations. These additional protective requirements include more extensive geologic testing, detailed computational modeling of the project area and periodic re-evaluations, detailed requirements for monitoring and tracking the CO_2 plume and pressure in the injection zone, unique financial responsibility requirements, and extended post-injection monitoring and site care.

UIC Class VI permits are designed to ensure that geologic sequestration does not cause the movement of injected CO_2 or formation fluids outside the authorized injection zone; if monitoring indicates leakage of injected CO_2 from the injection zone, the leakage may trigger a response per the permittee's Class VI Emergency and Remedial Response Plan including halting injection, and the permitting authority may prescribe additional permit requirements necessary to prevent such movement to ensure USDWs are protected or take appropriate enforcement action if the permit has been violated.[523] Class II EOR permits are also designed to ensure the protection of USDWs with requirements appropriate for the risks of the enhanced recovery operation. In general, the EPA believes that the protection of USDWs by preventing leakage of injected CO_2 out of the injection zone will also ensure that CO_2 is sufficiently sequestered in the subsurface, and therefore will not leak from the subsurface to the atmosphere.

The UIC program works with injection well operators throughout the life of the well to confirm practices do not pose a risk to USDWs. The program conducts inspections to verify compliance with the UIC permit, including checking for leaks.[524] Inspections are only one way that programs deter noncompliance. Programs also evaluate periodic monitoring reports submitted by operators and discuss potential issues with operators. If a well is found to be out of compliance with applicable requirements in its permit or UIC regulations, the program will identify specific actions that an operator must take to address the issues. The UIC program may assist the operator in returning the well to compliance or use administrative or judicial enforcement to return a well to compliance.

UIC program requirements address potential safety concerns with induced seismicity. More specifically, through the UIC Class VI program, the EPA has put in place mechanisms to identify, monitor, and reduce risks associated with induced seismicity in any areas within or surrounding a sequestration site through permit and program requirements such as site characterization and monitoring, and the requirement for applicants to demonstrate that induced seismic activity will not endanger USDWs.[525] The National Academy of Sciences released a report in 2012 on induced seismicity from CCS and determined that with appropriate site selection, a monitoring program, a regulatory system, and the appropriate use of remediation methods, the induced seismicity risks of geologic sequestration could be mitigated.[526] Furthermore, the Ground Water Protection Council and Interstate Oil and Gas Compact Commission have published a ''Potential Induced Seismicity Guide.'' This report found that the strategies for avoiding, mitigating, and responding to potential risks of induced seismicity should be determined based on site-specific characteristics (*i.e.,* local geology). These strategies could include supplemental seismic monitoring, altering operational parameters (such as rates and pressures) to reduce the ground motion hazard and risk, permit modification, partial plug back of the well, controlled restart (if feasible), suspending or revoking injection authorization, or stopping injection and shutting in a well.[527] The EPA's UIC National Technical Workgroup released technical recommendations in 2015 to address induced seismicity concerns in Class II wells and elements of these recommendations have been utilized in developing Class VI emergency and remedial response plans for Class VI permits.[528] [529] For example, as identified

[520] EPA. EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

[521] See 40 CFR parts 124, 144–147.

[522] EPA. (2010). Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells; Final Rule, 75 FR 77230, December 10, 2010 (codified at 40 CFR part 146, subpart H).

[523] See 40 CFR 144.12(b) (prohibition of movement of fluid into USDWs); 40 CFR 146.86(a)(1) (Class VI injection well construction requirements); 40 CFR 146(a) (Class VI injection well operation requirements); 40 CFR 146.94 (emergency and remedial response).

[524] EPA. (2020). Underground Injection Control Program. *https://www.epa.gov/sites/default/files/2020-04/documents/uic_fact_sheet.pdf.*

[525] *See* 40 CFR 146.82(a)(3)(v) (requiring the permit applicant to submit and the permitting authority to consider information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment); EPA. (2018). Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. U.S. Environmental Protection Agency Office of Water (4606M) EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[526] National Research Council. (2013). Induced Seismicity Potential in Energy Technologies. Washington, DC: The National Academies Press. *https://doi.org/10.17226/13355.*

[527] Ground Water Protection Council and Interstate Oil and Gas Compact Commission. (2021). Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection. *https://www.gwpc.org/wp-content/uploads/2022/12/FINAL_Induced_Seismicity_2021_Guide_33021.pdf.*

[528] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[529] EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/*

Continued

by the EPA's UIC National Technical Workgroup, sufficient pressure buildup from disposal activities, the presence of Faults of Concern (*i.e.,* a fault optimally oriented for movement and located in a critically stressed region), and the existence of a pathway for allowing the increased pressure to communicate with the fault contribute to the risk of injection-induced seismicity. The UIC requirements, including site characterization (*e.g.,* ensuring the confining zone [530] is free of faults of concern) and operating requirements (*e.g.,* ensuring injection pressure in the injection zone is below the fracture pressure), work together to address these components and reduce the risk of injection-induced seismicity, particularly any injection-induced seismicity that could be felt by people at the surface.[531] Additionally, the EPA recommends that Class VI permits include an approach for monitoring for seismicity near the site, including seismicity that cannot be felt at the surface, and that injection activities be stopped or reduced in certain situations if seismic activity is detected to ensure that no seismic activity will endanger USDWs.[532] This also reduces the likelihood of any future injection-induced seismic activity that will be felt at the surface.

Furthermore, during site characterization, if any of the geologic or seismic data obtained indicate a substantial likelihood of seismic activity, the EPA may require further analyses, potential planned operational changes, and additional monitoring.[533] The EPA has the authority to require seismic monitoring as a condition of the UIC permit if appropriate, or to deny the permit if the injection-induced seismicity risk could endanger USDWs.

The EPA believes that meaningful engagement with local communities is an important step in the development of geologic sequestration projects and has programs and public participation requirements in place to support this process. The EPA is committed to advancing EJ for overburdened communities in all its programs, including the UIC Class VI program.[534] The EPA is also committed to supporting states' and tribes' efforts to obtain UIC Class VI primacy and strongly encourages such states and tribes to incorporate environmental justice principles and equity into proposed UIC Class VI programs.[535] The EPA is taking steps to address EJ in accordance with Presidential Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All* (88 FR 25251, April 26, 2023). In 2023, the EPA released *Environmental Justice Guidance for UIC Class VI Permitting and Primacy* that builds on the 2011 *UIC Quick Reference Guide: Additional Tools for UIC Program Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process.*[536] [537] The 2023 guidance serves as an operating framework for identifying, analyzing, and addressing EJ concerns in the context of implementing and overseeing UIC permitting and primacy programs, including primacy approvals. The EPA notes that while this guidance is focused on the UIC Class VI program, EPA Regions should apply them to the other five injection well classes wherever possible, including class II. The guidance includes recommended actions across five themes to address various aspects of EJ in UIC Class VI permitting including: (1) identify communities with potential EJ concerns, (2) enhance public involvement, (3) conduct appropriately scoped EJ assessments, (4) enhance transparency throughout the permitting process, and (5) minimize adverse effects to USDWs and the communities they may serve.[538]

As a part of the UIC Class VI permit application process, applicants and the EPA Regions should complete an EJ review using the EPA's EJScreen Tool, an online mapping tool that integrates numerous demographic, socioeconomic, and environmental data sets that are overlain on an applicant's UIC Area of Review to identify whether any disadvantaged communities are encompassed.[539] If the results indicate a potential EJ impact, applicants and the EPA Regions should consider potential measures to mitigate the impacts of the UIC Class VI project on identified vulnerable communities and enhance the public participation process to be inclusive of all potentially affected communities *(e.g.,* conduct early targeted outreach to communities and identify and mitigate any communication obstacles such as language barriers or lack of technology resources).[540]

ER technologies are used in oil and gas reservoirs to increase production. Injection wells used for ER are regulated through the UIC Class II program. Injection of CO_2 is one of several techniques used in ER. Sometimes ER uses CO_2 from anthropogenic sources such as natural gas processing, ammonia and fertilizer production, and coal gasification facilities. Through the ER process, much of the injected CO_2 is recovered from production wells and can be separated and reinjected into the subsurface formation, resulting in the storage of CO_2 underground. The EPA's Class II regulations were designed to regulate ER injection wells, among other injection wells associated with oil and natural gas production. See *e.g.,* 40 CFR 144.6(b)(2). The EPA's Class II program is designed to prevent Class II injection activities from endangering USDWs. The Class II programs of states and tribes must be approved by the EPA and must meet the EPA regulatory requirements for Class II programs, 42 U.S.C. 300h–1, or otherwise represent an effective program to prevent endangerment of USDWs. 42 U.S.C 300h–4.

documents/implementation_manual_508_010318.pdf.

[530] ''Confining zone'' means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone. 40 CFR 146.3.

[531] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[532] See EPA. Emergency and Remedial Response Plan: 40 CFR 146.94(a) template. *https://www.epa.gov/system/files/documents/2022-03/err_plan_template.docx.* See also EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[533] 40 CFR 146.82(a)(3)(v).

[534] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf; see also* EPA. Letter from the EPA Administrator Michael S. Regan to U.S. State Governors. December 9, 2022. *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[535] EPA. (2023). Targeted UIC program grants for Class VI Wells. *https://www.epa.gov/uic/underground-injection-control-grants#ClassVI_Grants.*

[536] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[537] EPA. (2011). Geologic Sequestration of Carbon Dioxide—UIC Quick Reference Guide. *https://www.epa.gov/sites/default/files/2015-07/documents/epa816r11002.pdf.*

[538] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[539] EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

[540] EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf.*

In promulgating the Class VI regulations, the EPA recognized that if the business model for ER shifts to focus on maximizing CO_2 injection volumes and permanent storage, then the risk of endangerment to USDWs is likely to increase. As an ER project shifts away from oil and/or gas production, injection zone pressure and carbon dioxide volumes will likely increase if carbon dioxide injection rates increase, and the dissipation of reservoir pressure will decrease if fluid production from the reservoir decreases. Therefore, the EPA's regulations require the operator of a Class II well to obtain a Class VI permit when there is an increased risk to USDWs. 40 CFR 144.19.[541] While the EPA's regulations require the Class II well operator to assess whether there is an increased risk to USDWs (considering factors identified in the EPA's regulations), the permitting authority can also make this assessment and, in the event that an operator makes changes to Class II operations such that the increased risk to USDWs warrants transition to Class VI and the operator does not notify the permitting authority, the operator may be subject to SDWA enforcement and compliance actions to protect USDWs, including cessation of injection. The determination of whether there is an increased risk to USDWs would be based on factors specified in 40 CFR 144.19(b), including increase in reservoir pressure within the injection zone; increase in CO_2 injection rates; and suitability of the Class II Area of Review (AoR) delineation.

(c) Greenhouse Gas Reporting Program (GHGRP)

The GHGRP requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the United States. Approximately 8,000 facilities are required to report their emissions, injection, and/or supply activity annually, and the non-confidential reported data are made available to the public around October of each year. To complement the UIC regulations, the EPA included in the GHGRP air-side monitoring and reporting requirements for CO_2 capture, underground injection, and geologic sequestration. These requirements are included in 40 CFR part 98, subpart RR and subpart VV, also referred to as ''GHGRP subpart RR'' and ''GHGRP subpart VV.''

GHGRP subpart RR applies to ''any well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations'' [542] and provides the monitoring and reporting mechanisms to quantify CO_2 storage and to identify, quantify, and address potential leakage. The EPA designed GHGRP subpart RR to complement the UIC monitoring and testing requirements. See *e.g.,* 40 CFR 146.90–91. Reporting under GHGRP subpart RR is required for, but not limited to, all facilities that have received a UIC Class VI permit for injection of CO_2.[543] Under existing GHGRP regulations, facilities that conduct ER in Class II wells are not subject to reporting data under GHGRP subpart RR unless they have chosen to submit a proposed monitoring, reporting, and verification (MRV) plan to the EPA and received an approved plan from the EPA. Facilities conducting ER and who do not choose to submit a subpart RR MRV plan to the EPA would otherwise be required to report CO_2 data under subpart UU.[544] GHGRP subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the mass of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; report the mass of CO_2 sequestered using a mass balance approach; and report annual monitoring activities.[545] [546] [547] [548] Extensive subsurface monitoring is required for UIC Class VI wells at 40 CFR 146.90 and is the primary means of determining if the injected CO_2 remains in the authorized injection zone and otherwise does not endanger any USDW, and monitoring under a GHGRP subpart RR MRV Plan complements these requirements. The MRV plan includes five major components: a delineation of monitoring areas based on the CO_2 plume location; an identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways; a strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs; an approach for establishing the expected baselines for monitoring CO_2 surface leakage; and, a summary of considerations made to calculate site-specific variables for the mass balance equation.[549]

In April 2024, the EPA finalized a new GHGRP subpart, ''Geologic Sequestration of Carbon Dioxide with Enhanced Oil Recovery (EOR) Using ISO 27916'' (or GHGRP subpart VV).[550] GHGRP subpart VV applies to facilities that quantify the geologic sequestration of CO_2 in association with EOR operations in conformance with the ISO standard designated as CSA/ANSI ISO 27916:2019, Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery. Facilities that have chosen to submit an MRV plan and report under GHGRP subpart RR must not report data under GHGRP subpart VV. GHGRP subpart VV is largely modeled after the requirements in this ISO standard and focuses on quantifying storage of CO_2. Facilities subject to GHGRP subpart VV must include in their GHGRP annual report a copy of their EOR Operations Management Plan (EOR OMP). The EOR OMP includes a description of the EOR complex and engineered system, establishes that the EOR complex is adequate to provide safe, long-term containment of CO_2, and includes site-specific and other information including a geologic characterization of the EOR complex, a description of the facilities within the EOR project, a description of all wells and other engineered features in the EOR project, and the operations history of the project reservoir.[551]

Based on the understanding developed from existing projects, the security of sequestered CO_2 is expected to increase over time after injection ceases.[552] This is due to trapping mechanisms that reduce CO_2 mobility over time (*e.g.,* physical CO_2 trapping by a low-permeability geologic seal or chemical trapping by conversion or adsorption).[553] The EPA acknowledges the potential for some leakage of CO_2 to the atmosphere at sequestration sites, primarily while injection operations are active. For example, small quantities of the CO_2 that were sent to the

[541] EPA. (2015). Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI. *https://www.epa.gov/sites/default/files/2015-07/documents/class2eorclass6memo_1.pdf.*

[542] See 40 CFR 98.440.

[543] 40 CFR 98.440.

[544] As discussed in section X.C.5.b, entities conducting CCS to comply with this rule would be required to send the captured CO_2 to a facility that reports data under subpart RR or subpart VV.

[545] 40 CFR 98.446.

[546] 40 CFR 98.448.

[547] 40 CFR 98.446(f)(9) and (10).

[548] 40 CFR 98.446(f)(12).

[549] 40 CFR 98.448(a).

[550] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[551] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[552] ''Report of the Interagency Task Force on Carbon Capture and Storage.'' 2010. *https://www.osti.gov/servlets/purl/985209.*

[553] See, *e.g.,* Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

sequestration site may be emitted from leaks in pipes and valves that are traversed before the CO_2 actually reaches the sequestration formation. However, the EPA's robust UIC regulatory protections protect against leakage out of the injection zone. Relative to the 46.75 million metric tons of CO_2 reported as sequestered under subpart RR of the GHGRP between 2016 to 2022, only 196,060 metric tons were reported as leakage/emissions to the atmosphere in the same time period (representing less than 0.5% of the sequestration amount). Of these emissions, most were from equipment leaks and vented emissions of CO_2 from equipment located on the surface rather than leakage from the subsurface.[554] Furthermore, any leakage of CO_2 at a sequestration facility would be required to be quantified and reported under the GHGRP subpart RR or subpart VV, and such data are made publicly available on the EPA's website.

(5) Timing of Permitting for Sequestration Sites

As previously discussed, the EPA is the Class VI permitting authority for states, tribes, and territories that have not obtained primacy over their Class VI programs.[555] The EPA is committed to reviewing UIC Class VI permits as expeditiously as possible when the agency is the permitting authority. The EPA has the experience to properly regulate and review permits for UIC Class VI injection wells, and technical experts of multiple disciplines to review permit applications submitted to the EPA.

The EPA has seen a considerable uptick in Class VI permit applications over the past few years. The 2018 passage of revisions and enhancements to the IRC section 45Q tax credit that provides tax credits for carbon oxide (including CO_2) sequestration has led to an increase in Class VI permit applications submitted to the EPA. The 2022 IRA further expanded the IRC section 45Q tax credit and the 2021 IIJA established a $50 million program for grants to help states and tribes in developing and implementing a UIC Class VI primacy program, leading to even more interest in this area.[556] Between 2011, when the Class VI rule went into effect, and 2020, the EPA received a total of 8 permit applications for Class VI wells. The EPA then received 12 Class VI permit applications in 2021, 44 in 2022, and 123 in 2023. As of March 2024, the EPA has 130 Class VI permit applications under review (56 permit applications were transferred to Louisiana in February 2024 when the EPA rule granting Class VI primacy to the state became effective). The majority of those 130 permit applications (63%) were submitted to the EPA within the past 12 months. Also, as of March 2024, the EPA has issued eight Class VI permits, including six for projects in Illinois and two for projects in Indiana, and has released for public comment four additional draft permits for proposed projects in California. Two of the permits are in the pre-operation phase, one is in the injection phase, and one is in the post-injection monitoring phase.

In light of the recent flurry of interest in this area, the EPA is devoting increased resources to the Class VI program, including through increased staffing levels in order to meet the increased demand for action on Class VI permit applications.[557] Reviewing a Class VI permit application entails a multidisciplinary evaluation to determine whether the application includes the required information, is technically accurate, and supports a risk-based determination that underground sources of drinking water will not be endangered by the proposed injection activity. A wide variety of technical experts—from geologists to engineers to physical scientists—review permit applications submitted to the EPA. The EPA has been working to develop staff expertise and increase capacity in the UIC program, and the agency has effectively deployed appropriated resources over the last five years to scale UIC program staff from a few employees to the equivalent of more than 25 full-time employees across the agency's headquarters and regional offices. We expect that the additional resources and staff capacity for the Class VI program will lead to increased efficiencies in the Class VI permitting process.

In addition to increased staffing resources, the EPA has made considerable improvements to the Class VI permitting process to reduce the time needed to make final permitting decisions for Class VI wells while maintaining a robust and thorough review process that ensures USDWs are protected. The EPA has created additional resources for applicants including upgrading the Geologic Sequestration Data Tool (GSDT) to guide applicants through the application process.[558] The EPA has also created resources for permit writers including training series and guidance documents to build capacity for Class VI permitting.[559] Additionally, the EPA issued internal guidelines to streamline and create uniformity and consistency in the Class VI permitting process, which should help to reduce permitting timeframes. These internal guidelines include the expectation that EPA Regions will classify all Class VI well applications received on or after December 12, 2023, as applications for major new UIC injection wells, which requires the Regions to develop project decision schedules for reviewing Class VI permit applications. The guidelines also set target timeframes for components of the permitting process, such as the number of days EPA Regions should set for public comment periods and for developing responses to comments and final permit decisions. The EPA will continue to evaluate its internal UIC permitting processes to identify potential opportunities for streamlining and other improvements over time. Although the available data for Class VI wells is limited, the timeframe for processing Class I wells, which follows a similar regulatory structure, is typically less than 2 years.[560]

The EPA notes that a Class VI permit tracker is available on its website.[561] This tracker shows information for the 44 projects (representing 130 wells) that have submitted Class VI applications to the EPA, including details such as the current permit review stage, whether a project has been sent a Notice of Deficiency (NOD) or Request for Additional Information (RAI), and the applicant's response time to any NODs or RAIs. As mentioned above, most of the permits submitted to the EPA have been submitted within the past 12

[554] Based on subpart RR data retrieved from the EPA Facility Level Information on Greenhouse Gases Tool (FLIGHT), at *https://ghgdata.epa.gov/ghgp/main.do*. Retrieved March 2024.

[555] See 40 CFR part 145 (State UIC Program Requirements), 40 CFR part 147 (State, Tribal, and EPA-Administered Underground Injection Control Programs).

[556] EPA. (2023). Targeted UIC program grants for Class VI Wells *https://www.epa.gov/uic/underground-injection-control-grants#ClassVI_Grants*.

[557] EPA. (2023). Testimony Of Mr. Bruno Pigott, Principal Deputy Assistant Administrator for Water, U.S. Environmental Protection Agency, Hearing On Carbon Capture And Storage. *https://www.epa.gov/system/files/documents/2023-11/testimony-pigott-senr-hearing-nov-2-2023_-cleared.pdf*.

[558] EPA. (2023). Geologic Sequestration Data Tool (GSDT). *https://www.epa.gov/system/files/documents/2023-10/geologic-sequestration-data-tool_factsheet_oct2023.pdf*.

[559] EPA. (2023). Final Class VI Guidance Documents. *https://www.epa.gov/uic/final-class-vi-guidance-documents*.

[560] EPA Report to Congress: Class VI Permitting. 2022. *https://www.epa.gov/system/files/documents/2022-11/EPAClassVIPermittingReporttoCongress.pdf*.

[561] EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa*.

months. The EPA aims to review complete Class VI applications and issue permits when appropriate within approximately 24 months. This timeframe is dependent on several factors, including the complexity of the project and the quality and completeness of the submitted application. It is important for the applicant to submit a complete application and provide any information requested by the permitting agency in a timely manner so as not to extend the overall time for the review.

States may apply to the EPA for primacy to administer the Class VI programs within their states. The primacy application process has four phases: (1) pre-application activities, (2) completeness review and determination, (3) application evaluation, and (4) rulemaking and codification. To date, three states have been granted primacy for Class VI wells, including North Dakota, Wyoming, and most recently Louisiana.[562] As discussed above, North Dakota has issued 6 Class VI permits since receiving Class VI primacy in 2018, and Wyoming issued its first three Class VI permits in December 2023.[563] [564] [565] The EPA finalized a rule granting Louisiana Class VI primacy in January 2024 and the state's program became effective in February 2024. At that time, EPA Region 6 transferred 56 Class VI permit applications for projects in Louisiana to the state for continued review and permit issuance if appropriate. Prior to receiving primacy, the state worked with the EPA in understanding where each application was in the evaluation process. Currently, the EPA is working with the states of Texas, Arizona, and West Virginia as they are developing their UIC primacy applications.[566] Arizona submitted a primacy application to the EPA on February 13, 2024.[567] Texas and West Virginia are engaging with the EPA to complete pre-application activities.[568] If more states apply for and receive Class VI primacy, the number of permits in EPA review is expected to be reduced. The EPA has also created resources for regulators including training series and guidance documents to build capacity for Class VI permitting within UIC programs across the U.S. Through state primacy for Class VI programs, state expertise and capacity can be leveraged to support effective and efficient permit application reviews. The IIJA established a $50 million grant program to support states, Tribes, and territories in developing and implementing UIC Class VI programs. The EPA has allocated $1,930,000 to each state, tribe, and territory that submitted letters of intent.[569]

(6) Comments Received on Geologic Sequestration and Responses

The EPA received comments on geologic sequestration. Those comments, and the EPA's responses, are as follows.

Comment: Some commenters expressed concerns that the EPA has not demonstrated the adequacy of carbon sequestration at a commercial scale.

Response: The EPA disagrees that commercial carbon sequestration capacity will be inadequate to support this rule. As detailed in section VII.C.1.a.i(D)(1), commercial geologic sequestration capacity is growing in the United States. Multiple commercial sequestration facilities, other than those funded under EPAct05, are in construction or advanced development, with some scheduled to open for operation as early as 2025.[570] These facilities have proposed sequestration capacities ranging from 0.03 to 6 million tons of CO_2 per year. The EPA and states with approved UIC Class VI programs (including Wyoming, North Dakota, and Louisiana) are currently reviewing UIC Class VI geologic sequestration well permit applications for proposed sequestration sites in fourteen states.[571] [572] [573] As of March 2024, there are 44 projects with 130 injection wells are under review by the EPA.[574] Furthermore, the EPA anticipates that as the demand for commercial sequestration grows, more commercial sites will be developed in response to financial incentives.

Comment: Some commenters expressed concern about leakage of CO_2 from sequestration sites.

Response: The EPA acknowledges the potential for some leakage of CO_2 to the atmosphere at sequestration sites (such as leaks through valves before the CO_2 reaches the injection formation). However, as detailed in the preceding sections of preamble, the EPA's robust UIC permitting process is adequate to protect against CO_2 escaping the authorized injection zone (and then entering the atmosphere). As discussed in the preceding section, leakage out of the injection zone could trigger emergency and remedial response action including ceasing injection, possible permit modification, and possible enforcement action. Furthermore, the GHGRP subpart RR and subpart VV regulations prescribe accounting methodologies for facilities to quantify and report any potential leakage at the surface, and the EPA makes sequestration data and related monitoring plans publicly available on its website. The reported emissions/leakage from sequestration sites under subpart RR is a comparatively small fraction (less than 0.5 percent) of the associated sequestration volumes, with most of these reported emissions attributable to leaks or vents from surface equipment.

Comment: Some commenters expressed concern over safety due to induced seismicity.

Response: The EPA believes that the UIC program requirements adequately address potential safety concerns with induced seismicity at site-adjacent communities. More specifically, through the UIC Class VI program the EPA has put in place mechanisms to identify,

[562] On December 28, 2023, the EPA Administrator signed a final rule granting Louisiana's request for primacy for UIC Class VI junction wells located within the state. See EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[563] Wyoming Department of Environmental Quality. (2023). Wyoming grants its first three Class VI permits. *https://deq.wyoming.gov/2023/12/wyoming-grants-its-first-three-class-vi-permits/.*

[564] Ibid.

[565] Arnold & Porter. (2023). EPA Provides Increased Transparency in Class VI Permitting Process; Now Incorporated in Update to Interactive CCUS State Tracker. *https://www.arnoldporter.com/en/perspectives/blogs/environmental-edge/2023/11/ccus-state-legislative-tracker.*

[566] EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[567] Arizona Department of Environmental Quality. (2024). Underground Injection Control (UIC) Program. *https://azdeq.gov/UIC.*

[568] EPA. (2023). Underground Injection Control (UIC) Primary Enforcement Authority for the Underground Injection Control Program. U.S. Environmental Protection Agency. *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*

[569] EPA. (2023). Underground Injection Control (UIC) Class VI Grant Program. *https://www.epa.gov/system/files/documents/2023-11/uic-class-vi-grant-fact-sheet.pdf.*

[570] Global CCS Institute. (2024). Global Status of CCS 2023. *https://www.globalccsinstitute.com/wp-content/uploads/2024/01/Global-Status-of-CCS-Report-1.pdf.*

[571] UIC regulations for Class VI wells authorize the injection of CO_2 for geologic sequestration while protecting human health by ensuring the protection of underground sources of drinking water. The major components to be included in UIC Class VI permits are detailed further in section VII.C.1.a.i(D)(4).

[572] U.S. EPA Class VI Underground Injection Control (UIC) Class VI Wells Permitted by EPA as of January 25, 2024. *https://www.epa.gov/uic/table-epas-draft-and-final-class-vi-well-permits* Last updated January 19, 2024.

[573] EPA. (2024). Current Class VI Projects under Review at EPA. *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*

[574] Ibid.

monitor, and mitigate risks associated with induced seismicity in any areas within or surrounding a sequestration site through permit and program requirements, such as site characterization and monitoring, and the requirement for applicants to demonstrate that induced seismic activity will not endanger USDWs.[575] See section VII.C.1.a.i(D)(4)(b) for further discussion of mitigating induced seismicity risk. Although the UIC Class II program does not have specific requirements regarding seismicity, it includes discretionary authority to add additional conditions to a UIC permit on a case-by-case basis. The EPA created a document outlining practical approaches for UIC Directors to use to minimize and manage injection-induced seismicity in Class II wells.[576] Furthermore, during site characterization, if any of the geologic or seismic data obtained indicate a substantial likelihood of seismic activity, further analyses, potential planned operational changes, and additional monitoring may be required.[577] The EPA has the authority to require seismic monitoring as a condition of the UIC permit if appropriate, or to deny the permit if the injection-induced seismicity risk could endanger USDWs.

Comment: Some commenters have expressed concern that the EPA has not meaningfully engaged with historically disadvantaged and overburdened communities who may be impacted by environmental changes due to geologic sequestration.

Response: The EPA acknowledges that meaningful engagement with local communities is an important step in the development of geologic sequestration projects and has programs and public participation requirements in place to support this process. The EPA is committed to advancing environmental justice for overburdened communities in all its programs, including the UIC Class VI program.[578] The EPA's environmental justice guidance for Class VI permitting and primacy states that many of the expectations are broadly applicable, and EPA Regions should apply them to the other five injection well classes, including Class II, wherever possible.[579] See section VII.C.1.a.i(D)(4) for a detailed discussion of environmental justice requirements and guidance.

Comment: Commenters expressed concern that companies are not always in compliance with reporting requirements for subpart RR when required for other Federal programs.

Response: The EPA recognizes the need for geologic sequestration facilities to comply with the reporting requirements of the GHGRP, and acknowledges that there have been instances of entities claiming geologic sequestration under non-EPA programs (*e.g.,* to qualify for IRC section 45Q tax credits) while not having an EPA-approved MRV plan or reporting data under subpart RR.[580] The EPA does not implement the IRC section 45Q tax credit program, and it is not privy to taxpayer information. Thus, the EPA has no role in implementing or enforcing these tax credit claims, and it is unclear, for example, whether these companies would have been required by GHGRP regulations to report data under subpart RR, or if they would have been required only by the IRC section 45Q rules to opt-in to reporting under subpart RR. The EPA disagrees that compliance with the GHGRP would be a problem for this rule because the rule requires any affected unit that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the captured CO_2 underground to report under GHGRP subpart RR or GHGRP subpart VV. Unlike the IRC section 45Q tax credit program, which is implemented by the Internal Revenue Service (IRS), the EPA will have the information necessary to discern whether a facility is in compliance with any applicable GHGRP requirements. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility that reports in accordance with GHGRP subpart RR or GHGRP subpart VV. For more information on the relationship to GHGRP requirements, see section X.C.5 of this preamble.

Comment: Commenters expressed concerns that UIC regulations allow Class II wells to be used for long-term CO_2 storage if the operator assesses that a Class VI permit is not required and asserted that Class II regulations are less protective than Class VI regulations.

Response: The EPA acknowledges that Class II wells for EOR may be used to inject CO_2 including CO_2 captured from an EGU. However, the EPA disagrees that the use of Class II wells for ER will be less protective of human health than the use of Class VI wells for geologic sequestration. Class II wells are used only to inject fluids associated with oil and natural gas production, and Class II ER wells are used specifically for the injection of fluids, including CO_2, for the purpose of enhanced recovery of oil or natural gas. The EPA's UIC Class II program is designed to prevent Class II injection activities from endangering USDWs. Any leakage out of the designated injection zone could pose a risk to USDWs and therefore could be subject to enforcement action or permit modification. Therefore, the EPA believes that UIC protections for USDWs would also ensure that the injected CO_2 is contained in the subsurface formations. The Class II programs of states and tribes must be approved by the EPA and must meet EPA regulatory requirements for Class II programs, 42 U.S.C. 300h–1, or otherwise represent an effective program to prevent endangerment of USDWs. 42 U.S.C 300h–4. The EPA's regulations require the operator of a Class II well to obtain a Class VI permit when operations shift to geologic sequestration and there is consequently an increased risk to USDWs. 40 CFR 144.19. UIC Class VI regulations require that owners or operators must show that the injection zone has sufficient volume to contain the injected carbon dioxide stream and report any fluid migration out of the injection zone and into or between USDWs. 40 CFR 146.83 and 40 CFR 146.91. The EPA emphasizes that while CO_2 captured from an EGU can be injected into a Class II ER injection well, it cannot be injected into the other two types of Class II wells, which are Class II disposal wells and Class II wells for the storage of hydrocarbons. 40 CFR 144.6(b).

Comment: Some commenters expressed concern that because few Class VI permits have been issued, the EPA's current level of experience in properly regulating and reviewing permits for these wells is limited.

---

[575] EPA. (2018). Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors. EPA 816–R–18–001. *https://www.epa.gov/sites/default/files/2018-01/documents/implementation_manual_508_010318.pdf.*

[576] EPA. (2015). Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches. *https://www.epa.gov/sites/default/files/2015-08/documents/induced-seismicity-201502.pdf.*

[577] 40 CFR 146.82(a)(3)(v).

[578] EPA. (2023). Environmental justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf*; *see also* EPA. Letter from the EPA Administrator Michael S. Regan to U.S. State Governors. December 9, 2022. *https://www.epa.gov/system/files/documents/2022-12/AD.Regan_.GOVS_.Sig_.Class%20VI.12-9-22.pdf.*

[579] EPA. (2023). Environmental Justice Guidance for UIC Class VI Permitting and Primacy. *https://www.epa.gov/system/files/documents/2023-08/Memo%20and%20EJ%20Guidance%20for%20UIC%20Class%20VI_August%202023.pdf.*

[580] Letter from U.S. Treasury Inspector General for Tax Administration (TIGTA). (2020). *https://www.menendez.senate.gov/imo/media/doc/TIGTA%20IRC%2045Q%20Response%20Letter%20FINAL%2004-15-2020.pdf.*

Response: The EPA disagrees that the Agency lacks experience to properly regulate, and review permits for Class VI injection wells. We expect that the additional resources that have been allocated for the Class VI program will lead to increased efficiencies in the Class VI permitting process and timeframes. For a more detailed discussion of Class VI permitting and timeframes, see sections VII.C.1.a.i(D)(4)(b) and VII.C.1.a.i(D)(5) of this preamble. The EPA emphasizes that incomplete or insufficient application materials can result in substantially delayed permitting decisions. When the EPA receives incomplete or insufficient permit applications, the EPA communicates the deficiencies, waits to receive additional materials from the applicant, and then reviews any new data. This back and forth can result in longer permitting timeframes. The EPA therefore encourages applicants to contact their permitting authority early on so applicants can gain a thorough understanding of the Class VI permitting process and the permitting authority's expectations. To assist potential permit applicants, the EPA maintains a list of UIC contacts within each EPA Regional Office on the Agency's website.[581] The EPA has met with more than 100 companies and other interested parties.

Comment: Some commenters claimed that various legal uncertainties preclude a finding that geologic sequestration of CO_2 has been adequately demonstrated. This concern has been raised in particular with issues of pore space ownership and the lack of long-term liability insurance and noted uncertainties regarding long-term liability generally.

Response: The EPA disagrees that these uncertainties are sufficient to prohibit the development of geologic sequestration projects. An interagency CCS task force examined sequestration-related legal issues thoroughly and concluded that early CCS projects could proceed under the existing legal framework with respect to issues such as property rights and liability.[582] The development of CCS projects may be more complex in certain regions, due to distinct pore space ownership regulatory regimes at the state level, except on Federal lands.[583]

As discussed in section VII.C.1.a.i.(D)(4) of this preamble, Title V of the FLPMA and its implementing regulations, 43 CFR part 2800, authorize the BLM to issue ROWs to geologically sequester CO_2 in Federal pore space, including BLM ROWs for the necessary physical infrastructure and for the use and occupancy of the pore space itself. The BLM has published a policy defining access to pore space on BLM lands, including clarification of Federal policy for situations where the surface and pore space are under the control of different Federal agencies.[584]

States have established legislation and regulations defining pore space ownership and providing clarification to prospective users of surface pore space. For example, in North Dakota, the surface owner also owns the pore space underlying their surface estate.[585] North Dakota state courts have determined that in situations where the surface ownership and mineral ownership have been legally severed the mineral estate is the dominant estate and has the right to use as much of the surface estate as reasonably necessary. The North Dakota legislature codified this interpretation in 2019.[586] Summit Carbon Solutions, which is developing a carbon storage hub in North Dakota to store an estimated one billion tons of CO_2, indicated that they had secured the majority of the pore space needed through long term leases with landowners.[587] Wyoming defines ownership of pore space underlying surfaces within the state.[588] Other states have also established laws, implementing regulations and guidance defining ownership and access to pore space. The EPA notes that many states are actively enacting legislation addressing pore space ownership. See *e.g.,* Wyoming H.B. No. 89 (2008) (Wyo. Stat. § 34–1–152); Montana S.B. No. 498 (2009) (Mont. Code Ann. 82–11–180); North Dakota S.B. No. 2139 (2009) (N.D. Cent. Code § 47–31–03); Kentucky H.B. 259 (2011) (Ky. Rev. Stat. Ann. § 353.800); West Virginia H.B. 4491 (2022) (W. Va. Code § 22–11B–18); California S.B. No. 905 (2022) (Cal. Pub. Res. Code § 71462); Indiana Public Law 163 (2022) (Ind. Code § 14–39–2–3); Utah H.B. 244 (2022) (Utah Code § 40–6–20.5).

Liability during operation is usually assumed by the project operator, so liability concerns primarily arise after the period of operations. Research has previously shown that the environmental risk is greatest before injection stops.[589] In terms of long-term liability and permittee obligations under the SDWA, the EPA's Class VI regulations impose various requirements on permittees even after injection ceases, including regarding injection well plugging (40 CFR 146.92), post-injection site care (PISC), and site closure (40 CFR 146.93). The default time period for post-injection site care is 50 years, during which the permittee must monitor the position of the CO_2 plume and pressure front and demonstrate that USDWs are not being endangered. 40 CFR 146.93. The permittee must also generally maintain financial responsibility sufficient to cover injection well plugging, corrective action, emergency and remedial response, PISC, and site closure until the permitting authority approves site closure. 40 CFR 146.85(a)&(b). Even after the former permittee has fulfilled all its UIC regulatory obligations, it may still be held liable for previous regulatory noncompliance, such as where the permittee provided erroneous data to support approval of site closure. A former permittee may always be subject to an order that the EPA Administrator deems necessary to protect public health if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW. 42 U.S.C. 300i; 40 CFR 144.12(e).

The EPA notes that many states are enacting legislation addressing long term liability. See *e.g.,* Montana S.B. No. 498 (2009) (Mont. Code Ann. 82–11–183); Texas H.B. 1796 (2009) (Tex. Health & Safety Code Ann. § 382.508); North Dakota S.B. No. 2095 (2009) (N.D. Cent. Code § 38–22–17); Kansas H.B.

[581] EPA. (2023). Underground Injection Control Class VI (Geologic Sequestration) Contact Information. *https://www.epa.gov/uic/underground-injection-control-class-vi-geologic-sequestration-contact-information.*

[582] Report of the Interagency Task Force on Carbon Capture and Storage. 2010. *https://www.energy.gov/fecm/articles/ccstf-final-report.*

[583] Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration. 2021. *https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

[584] National Policy for the Right-of-Way Authorizations Necessary for Site Characterization, Capture, Transportation, Injection, and Permanent Geologic Sequestration of Carbon Dioxide in Connection with Carbon Sequestration Projects. BLM IM 2022–041 Instruction Memorandum, June 8, 2022. *https://www.blm.gov/policy/im-2022-041.*

[585] ND DMR 2023. Pore Space in North Dakota. North Dakota Department of Mineral Resources *https://www.dmr.nd.gov/oilgas/ND_DMR_Pore_Space_Information.pdf.*

[586] Ibid.

[587] Summit Carbon Solutions. (2021). Summit Carbon Solutions Announces Significant Carbon Storage Project Milestones. (2021). *https://summitcarbonsolutions.com/summit-carbon-solutions-announces-significant-carbon-storage-project-milestones/.*

[588] Wyo. Stat § 34–1–152 (2022).

[589] Benson, S.M. (2007). Carbon dioxide capture and storage: research pathways, progress and potential. Presentation given at the Global Climate & Energy Project Annual Symposium, October 1, 2007. *https://drive.google.com/file/d/1ZvfRW92OqvBBAFs69SPHIWoYFGySMgtD/view.*

2418 (2010) (Kan. Stat. Ann. § 55–1637(h)); Wyoming S.F. No. 47 (2022) (Wyo. Stat. §§ 35–11–319); Louisiana H.B. 661 (2009) & H.B. 571 (2023) (La. Stat. Ann. § 30:1109). Because states are actively working to address pore space and liability uncertainties, the EPA does not believe these to be issues that would delay project implementation beyond the timelines discussed in this preamble.

(E) Compliance Date for Long-Term Coal-Fired Steam Generating Units

The EPA proposed a January 1, 2030 compliance date for long-term coal fired steam generating units subject to a CCS BSER. That compliance date assumed installation of CCS was concurrent with development of state plans. While several commenters were supportive of the proposed compliance date, the EPA also received comments on the proposed rule that stated that the proposed compliance date was not achievable. Commenters referenced longer project timelines for CO_2 capture. Commenters also requested that the EPA should account for the state plan process in determining the appropriate compliance date.

The EPA has considered the comments and information available and is finalizing a compliance date of January 1, 2032, for long-term coal-fired steam generating units. The EPA is also finalizing a mechanism for a 1-year compliance date extension in cases where a source faces delays outside its control, as detailed in section X.C.1.d of this preamble. The justification for the January 1, 2032 compliance date does not require substantial work to be done during the state planning process. Rather, the justification for the compliance date reflects the assumption that only the initial feasibility work which is necessary to inform the state planning process would occur during state plan development, with the start of more substantial work beginning after the due date for state plan submission, and a longer timeline for installation of CCS than at proposal. In total, this allows for 6 years and 7 months for both initial feasibility and more substantial work to occur after issuance of this rule. This is consistent with the approximately 6 years from start to finish for Boundary Dam Unit 3 and Petra Nova.

The timing for installation of CCS on existing coal-fired steam generating units is based on the baseline project schedule for the CO_2 capture plant developed by Sargent and Lundy (S&L[590] and a review of the available information for installation of CO_2 pipelines and sequestration sites.[591] Additional details on the timeline are in the TSD *GHG Mitigation Measures for Steam Generating Units,* available in the docket. The dates for intermediate steps are for reference. The specific sequencing of steps may differ slightly, and, for some sources, the duration of one step may be shorter while another may be longer, however the total duration is expected to be the same. The resulting timeline is therefore an accurate representation of the time necessary to install CCS in general.

The EPA assumes that feasibility work, amounting to less than 1 year (June 2024 through June 2025) for each component of CCS (capture, transport, and storage) occurs during the state plan development period (June 2024 through June 2026). This feasibility work is limited to initial conceptual design and other preliminary tasks, and the costs of the feasibility work in general are substantially less than other components of the project schedule. The EPA determined that it was appropriate to assume that this work would take place during the state plan development period because it is necessary for evaluating the controls that the state may determine to be appropriate for a source and is necessary for determining the resulting standard of performance that the state may apply to the source on the basis of those controls. In other words, without such feasibility and design work, it would be very difficult for a state to determine whether CCS is appropriate for a given source or the resulting standard of performance. While the EPA accounts for up to 1 year for feasibility for the capture plant, the S&L baseline schedule estimates this initial design activity can be completed in 6 months. For the capture plant, feasibility includes a preliminary technical evaluation to review the available utilities and siting footprint for the capture plant, as well as screening of the available capture technologies and vendors for the project, with an associated initial economic estimate. For sequestration, in many cases, general geologic characterization of regional areas has already been conducted by U.S. DOE and regional initiatives; however, the EPA assumes an up to 1 year period for a storage complex feasibility study. For the pipeline, the feasibility includes the initial pipeline routing analysis, taking less than 1 year. This exercise involves using software to review existing right-of-way and other considerations to develop an optimized pipeline route. Inputs to that analysis have been made publicly available by DOE in NETL's Pipeline Route Planning Database.[592]

When state plans are submitted 24 months after publication of the final rule, requirements included within those state plans should be effective at the state level. On that basis, the EPA assumes that sources installing CCS are fully committed, and more substantial work (*e.g.,* FEED study for the capture plant, permitting, land use and right-of-way acquisition) resumes in June 2026. The EPA notes, however, that it would be possible that a source installing CCS would choose to continue these activities as soon as the initial feasibility work is completed even if not yet required to do so, rather than wait for state plan submission to occur for the reasons explained in full below.

Of the components of CCS, the CO_2 capture plant is the more technically involved and time consuming, and therefore is the primary driver for determining the compliance date. The EPA assumes substantial work commences only after submission due date for state plans. The S&L baseline timeline accounts for 5.78 years (301 weeks) for final design, permitting, and installation of the CO_2 capture plant. First, the EPA describes the timeline that is consistent with the S&L baseline for substantial work. Subsequently, the EPA describes the rationale for slight adjustments that can be made to that timeline based upon an examination of actual project timelines.

In the S&L baseline, substantial work on the CO_2 capture plant begins with a 1-year FEED study (June 2026 to June 2027). The information developed in the FEED study is necessary for finalizing commercial arrangements. In the S&L baseline, the commercial arrangements can take up to 9 months (June 2027 to March 2028). Commercial arrangements include finalizing funding as well as finalizing contracts with a CO_2 capture technology provider and engineering, procurement, and construction companies. The S&L baseline accounts for 1 year for permitting, beginning when commercial arrangements are nearly complete (December 2027 to December 2028). After commercial arrangements are complete, a 2-year period for engineering and procurement begins (March 2028 to March 2030).

[590] CO_2 Capture Project Schedule and Operations Memo, Sargent & Lundy (2024). Available in Docket ID EPA–HQ–OAR–2023–0072.

[591] Transport and Storage Timeline Summary, ICF (2024). Available in Docket ID EPA–HQ–OAR–2023–0072.

[592] NETL Develops Pipeline Route Planning Database To Guide CO_2 Transport Decisions. May 31, 2023. *https://netl.doe.gov/node/12580.*

Detailed engineering starts after commercial arrangements are complete because engineers must consider details regarding the selected CO_2 capture technology, equipment providers, and coordination with construction. Shortly after permitting is complete, 6 months of sitework (March 2029 to September 2029) occur. Sitework is followed by 2 years of construction (July 2029 to July 2031). Approximately 8 months prior to the completion of construction, a roughly 14 month (60 weeks) period for startup and commissioning begins (January 2031 to March 2032).

In many cases, the EPA believes that sources are positioned to install CO_2 capture on a slightly faster timeline than the baseline S&L timeline detailed in the prior paragraph, because CCS projects have been developed in a shorter timeframe. Including these minor adjustments, the total time for detailed engineering, procurement, construction, startup and commissioning is 4 years, which is consistent with completed projects (Boundary Dam Unit 3 and Petra Nova) and project schedules developed in completed FEED studies, see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional details. In addition, the IRC tax credits incentivize sources to begin complying earlier to reap economic benefits earlier. Sources that have already completed feasibility or FEED studies, or that have FEED studies ongoing are likely to be able to have CCS fully operational well in advance of January 1, 2032. Ongoing projects have planned dates for commercial operation that are much earlier. For example, Project Diamond Vault has plans to be fully operational in 2028.[593] While the EPA assumes FEED studies start after the date for state plan submission, in practice sources are likely to install CO_2 capture as expeditiously as practicable. Moreover, the preceding timeline is derived from project schedules developed in the absence of any regulatory impetus. Considering these factors, sources have opportunities to slightly condense the duration, overlap, or sequencing of steps so that the total duration for completing substantial work on the capture plant is reduced by 2 months. For example, by expediting the duration for commercial arrangements from 9 months to 7 months, reasonably assuming sources immediately begin sitework as soon as permitting is complete, and accounting for 13 months (rather than 14) for startup and testing, the CO_2 capture plant will be fully operational by January 2032. Therefore, the EPA concludes that CO_2 capture can be fully operational by January 1, 2032. To the extent additional time is needed to take into account the particular circumstances of a particular source, the state may take those circumstances into account to provide a different compliance schedule, as detailed in section X.C.2 of this preamble.

The EPA also notes that there is additional time for permitting than described in the S&L baseline. The key permitting that affects the timeline are air permits because of the permits' impact on the ability to construct and operate the CCS capture equipment, in which the EPA is the expert in. The S&L baseline assumes permitting starts after the FEED study is complete while commercial arrangements are ongoing, however permitting can begin earlier allowing a more extended period for permitting. Examples of CCS permitting being completed while FEED studies are on-going include the air permits for Project Tundra, Baytown Energy Center, and Deer Park Energy Center. Therefore, while the FEED study is on-going, the EPA assumes that a 2-year process for permitting can begin.

The EPA's compliance deadline assumes that storage and pipelines for the captured CO_2 can be installed concurrently with deployment of the capture system. Substantial work on the storage site starts with 3 years (June 2026 to June 2029) for final site characterization, pore-space acquisition, and permitting, including at least 2 years for permitting of Class VI wells during that period. Lastly, construction for sequestration takes 1 year (June 2029 to June 2030). While the EPA assumes that storage can be permitted and constructed in 4 years, the EPA notes that there is at least an additional 12 months of time available to complete construction of the sequestration site without impacting progress of the other components.

The EPA assumes the substantial work on the pipeline lags the start of substantial work on the storage site by 6 months. After the 1 year of feasibility work prior to state plan submission, the general timeline for the CO_2 pipeline assumes up to 3 years for final routing, permitting activities, and right-of-way acquisition (December 2026 to December 2029). Lastly, there are 1.5 years for pipeline construction (December 2029 to June 2031).[594]

The EPA does not assume that CCS projects are, in general, subject to NEPA. NEPA review is required for reasons including sources receiving federal funding (*e.g.,* through USDA or DOE) or projects on federal lands. NEPA may also be triggered for a CCS project if NEPA compliance is necessary for construction of the pipeline, such as where necessary because of a Clean Water Act section 404 permit, or for sequestration. Generally, if one aspect of a project is subject to NEPA, then the other project components could be as well. In cases where a project is subject to NEPA, an environmental assessment (EA) that takes 1 year, can be finalized concurrently during the permitting periods of each component of CCS (capture, pipeline, and sequestration). However, the EPA notes that the final timeline can also accommodate a concurrent 2-year period if an EIS were required under NEPA across all components of the project. The EPA also notes that, in some circumstances, NEPA review may begin prior to completion of a FEED study. For Petra Nova, a notice of intent to issue an EIS was published on November 14, 2011, and the record of decision was issued less than 2 years later, on May 23, 2013,[595] while the FEED study was completed in 2014.

Based on this detailed analysis, the EPA has concluded that January 1, 2032, is an achievable compliance date for CCS on existing coal-fired steam generating units that takes into account the state plan development period, as well as the technical and bureaucratic steps necessary to install and implement CCS and is consistent with other expert estimates and real-world experience.

(F) Long-Term Coal-Fired Steam Generating Units Potentially Subject to This Rule

In this section of the preamble, the EPA estimates the size of the inventory of coal-fired power plants in the long-term subcategory likely subject to CCS as the BSER. Considering that capacity, the EPA also describes the distance to storage for those sources.

(1) Capacity of Units Potentially Subject to This Rule

First, the EPA estimates the total capacity of units that are currently operating and that have not announced plans to retire by 2039, or to cease firing

[593] Project Diamond Vault Overview. *https://www.cleco.com/docs/default-source/diamond-vault/project_diamond_vault_overview.pdf.*

[594] The summary timeline for CO_2 pipelines assumes feasibility for pipelines is 1 year, followed by 1.5 years for permitting, with the pipeline feasibility beginning 1 year after permitting for sequestration starts. The EPA assumes initial pipeline feasibility occurs up-front, with a longer period for final routing, permitting, and right-of-way acquisition.

[595] Petra Nova W.A. Parish Project. *https://www.energy.gov/fecm/petra-nova-wa-parish-project.*

coal by 2030. Starting from that first estimate, the EPA then estimates the capacity of units that would likely be subject to the CCS requirement, based on unit age, industry trends, and economic factors.

Currently, there are 181 GW of coal-fired steam generating units.[596] About half of that capacity, totaling 87 GW, have announced plans to retire before 2039, and an additional 13 GW have announced plans to cease firing coal by that time. The remaining amount, 81 GW, are likely to be the most that could potentially be subject to requirements based on CCS.

However, the capacity of affected coal-fired steam generating units that would ultimately be subject to a CCS BSER is likely approximately 40 GW. This determination is supported by several lines of analysis of the historical data on the size of the fleet over the past several years. Historical trends in the coal-fired generation fleet are detailed in section IV.D.3 of this preamble. As coal-fired units age, they become less efficient and therefore the costs of their electricity go up, rendering them even more competitively disadvantaged. Further, older sources require additional investment to replace worn parts. Those circumstances are likely to continue through the 2030s and beyond and become more pronounced. These factors contribute to the historical changes in the size of the fleet.

One way to analyze historical changes in the size of the fleet is based on unit age. As the average age of the coal-fired fleet has increased, many sources have ceased operation. From 2000 to 2022, the average age of a unit that retired was 53 years. At present, the average age of the operating fleet is 45 years. Of the 81 GW that are presently operating and that have not announced plans to retire or convert to gas prior to 2039, 56 GW will be 53 years or older by 2039.[597]

Another line of analysis is based on the rate of change of the size of the fleet. The final TSD, *Power Sector Trends,* available in the rulemaking docket, includes analysis showing sharp and steady decline in the total capacity of the coal-fired steam generating fleet. Over the last 15 years (2009–2023), average annual coal retirements have been 8 GW/year. Projecting that retirements will continue at approximately the same pace from now until 2039 is reasonable because the same circumstances will likely continue or accelerate further given the incentives under the IRA. Applying this level of annual retirement would result in 45 GW of coal capacity continuing to operate by 2039. Alternatively, the TSD also includes a graph that shows what the fleet would look like assuming that coal units without an announced retirement date retire at age 53 (the average retirement age of units over the 2000–2022 period). It shows that the amount of coal-fired capacity that remains in operation by 2039 is 38 GW.

The EPA also notes that it is often the case that coal-fired units announce that they plan to retire only a few years in advance of the retirement date. For instance, of the 15 GW of coal-fired EGUs that reported a 2022 retirement year in DOE's EIA Form 860, only 0.5 GW of that capacity had announced its retirements plans when reporting in to the same EIA–860 survey 5 years earlier, in 2017.[598] Thus, although many coal-fired units have already announced plans to retire before 2039, it is likely that many others may anticipate retiring by that date but have not yet announced it.

Finally, the EPA observes that modeling the baseline circumstances, absent this final rule, shows additional retirements of coal-fired steam generating units. At the end of 2022, there were 189 GW of coal active in the U.S. By 2039, the IPM baseline projects that there will be 42 GW of operating coal-fired capacity (not including coal-to-gas conversions). Between 2023–2039, 95 GW of coal capacity have announced retirement and an additional 13 have announced they will cease firing coal. Thus, of the 81 GW that have not announced retirement or conversion to gas by 2039, the IPM baseline projects 39 GW will retire by 2039 due to economic reasons.

For all these reasons, the EPA considers that it is realistic to expect that 42 GW of coal-fired generating will be operating by 2039—based on announced retirements, historical trends, and model projections—and therefore constitutes the affected sources in the long-term subcategory that would be subject to requirements based on CCS. It should be noted that the EPA does not consider the above analysis to predict with precision which units will remain in operation by 2039. Rather, the two sets of sources should be considered to be reasonably representative of the inventory of sources that are likely to remain in operation by 2039, which is sufficient for purposes of the BSER analysis that follows.

(2) Distance to Storage for Units Potentially Subject to This Rule

The EPA believes that it is conservative to assume that all 81 GW of capacity with planned operation during or after 2039 would need to construct pipelines to connect to sequestration sites. As detailed in section VII.B.2 of this preamble, the EPA is finalizing an exemption for coal-fired sources permanently ceasing operation by January 1, 2032. About 42 percent (34 GW) of the existing coal-fired steam generation capacity that is currently in operation and has not announced plans to retire prior to 2039 will be 53 years or older by 2032. As discussed in section VII.C.1.a.i(F), from 2000 to 2022, the average age of a coal unit that retired was 53 years old. Therefore, the EPA anticipates that approximately 34 GW of the total capacity may permanently cease operation by 2032 despite not having yet announced plans to do so. Furthermore, of the coal-fired steam generation capacity that has not announced plans to cease operation before 2039 and is further than 100 km (62 miles) of a potential saline sequestration site, 45 percent (7 GW) will be over 53 years old in 2032. Therefore, it is possible that much of the capacity that is further than 100 km (62 miles) of a saline sequestration site and has not announced plans to retire will permanently cease operation due to age before 2032 and thus the rule would not apply to them. Similarly, of the coal-fired steam generation capacity that has not announced plans to cease operation before 2039 and is further than 160 km (100 miles) of a potential saline sequestration site, 56 percent (4 GW) will be over 53 years old in 2032. Therefore, the EPA notes that it is possible that the majority of capacity that is further than 160 km (100 miles) of a saline sequestration and has not announced plans to retire site will permanently cease operation due to age before 2032 and thus be exempt from the requirements of this rule.

The EPA also notes that a majority (56 GW) of the existing coal-fired steam generation capacity that is currently in operation and has not announced plans to permanently cease operation prior to 2039 will be 53 years or older by 2039. Of the coal-fired steam generation capacity with planned operation during

[596] EIA December 2023 Preliminary Monthly Electric Generator Inventory. *https://www.eia.gov/electricity/data/eia860m/.*

[597] 81 GW is derived capacity, plant type, and retirement dates as represented in EPA NEEDS database. Total amount of covered capacity in this category may ultimately be slightly less (approximately) due to CHP-related exemptions.

[598] The survey Form EIA–860 collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater of combined nameplate capacity. Data available at *https://www.eia.gov/electricity/data/eia860/.*

or after 2039 that is not located within 100 km (62 miles) of a potential saline sequestration site, the majority (58 percent or 9 GW) of the units will be 53 years or older in 2039.[599] Consequently, the EPA believes that many of these units may permanently cease operation due to age prior to 2039 despite not at this point having announced specific plans to do so, and thereby would likely not be subject to a CCS BSER.

(G) Resources and Workforce To Install CCS

Sufficient resources and an available workforce are required for installation and operation of CCS. Raw materials necessary for CCS are generally available and include common commodities such as steel and concrete for construction of the capture plant, pipelines, and storage wells.

Drawing on data from recently published studies, the DOE completed an order-of-magnitude assessment of the potential requirements for specialized equipment and commodity materials for retrofitting existing U.S. coal-fueled EGUs with CCS.[600] Specialized equipment analyzed included absorbers, strippers, heat exchangers, and compressors. Commodity materials analyzed included monoethanolamine (MEA) solvent for carbon capture, triethylene glycol (TEG) for carbon dioxide drying, and steel and cement for construction of certain aspects of the CCS value chain.[601] The DOE analyzed one scenario in which 42 GW of coal-fueled EGUs are retrofitted with CCS and a second scenario in which 73 GW of coal-fueled EGUs are retrofitted with CCS.[602] The analysis determined that in both scenarios, the maximum annual commodity requirements to construct and operate the CCS systems are likely to be much less than their respective global production rates. The maximum requirements are expected to be at least one order of magnitude lower than global annual production for all of the commodities considered except MEA, which was estimated to be approximately 14 percent of global annual production in the 42 GW scenario and approximately 24 percent of global annual production in the 73 GW scenario.[603] For steel and cement, the maximum annual requirements are also expected to be at least one order of magnitude lower than U.S. annual production rates. Finally, the DOE analysis determined that it is unlikely that the deployment scenarios would encounter any bottlenecks in the supplies of specialized equipment (absorbers, strippers, heat exchangers, and compressors) because of the large pool of potential suppliers.

The workforce necessary for installing and operating CCS is readily available. The required workforce includes construction, engineering, manufacturing, and other skilled labor (*e.g.,* electrical, plumbing, and mechanical trades). The existing workforce is well positioned to meet the demand for installation and operation of CCS. Many of the skills needed to build and operate carbon capture plants are similar to those used by workers in existing industries, and this experience can be leveraged to support the workforce needed to deploy CCS. In addition, government programs, industry workforce investments, and IRC section 45Q prevailing wage and apprenticeship provisions provide additional significant support to workforce development and demonstrate that the CCS industry likely has the capacity to train and expand the available workforce to meet future needs.[604]

Overall, quantitative estimates of workforce needs indicates that the total number of jobs needed for deploying CCS on coal power plants is significantly less than the size of the existing workforce in adjacent occupations with transferrable skills in the electricity generation and fuels industries. The majority of direct jobs, approximately 90 percent, are expected to be in the construction of facilities, which tend to be project-based. The remaining 10 percent of jobs are expected to be tied to ongoing facility operations and maintenance.[605] Recent project-level estimates bear this out. The Boundary Dam CCS facility in Canada employed 1,700 people at peak construction.[606] A recent workforce projection estimates average annual jobs related to investment in carbon capture retrofits at coal power plants could range from 1,070 to 1,600 jobs per plant. A DOE memorandum estimates that 71,400 to 107,100 average annual jobs resulting from CCS project investments—across construction, project management, machinery installers, sales representatives, freight, and engineering occupations—would likely be needed over a five-year construction period [607] to deploy CCS at

[599] Sequestration potential as it relates to distance from existing resources is a key part of the EPA's regular power sector modeling development, using data from DOE/NETL studies. For details, please see chapter 6 of the IPM documentation available at:. *https://www.epa.gov/system/files/documents/2021-09/chapter-6-co2-capture-storage-and-transport.pdf*.

[600] DOE. Material Requirements for Carbon Capture and Storage Retrofits on Existing Coal-Fueled Electric Generating Units. *https://www.energy.gov/policy/articles/material-requirements-carbon-capture-and-storage-retrofits-existing-coal-fueled*.

[601] Steel requirements were assessed for carbon capture, transport and storage, but cement requirements were only assessed for capture and storage.

[602] DOE analyzed the resources—including specialized equipment, commodity materials, and, as discussed below, workforce, necessary for 73 GW of coal capacity to install CCS because that is the amount that has not announced plans to retire by January 1, 2040. As indicated in the final TSD, *Power Sector Trends,* a somewhat larger amount—81 GW—has not announced plans to retire or cease firing coal by January 1, 2039, and it is this latter amount that is the maximum that, at least in theory, could be subject to the CCS requirement. DOE's conclusions that sufficient resources are available also hold true for the larger amount.

[603] Although the assessment assumed that all of the CCS deployments would utilize MEA-based carbon capture technologies, future CCS deployments could potentially use different solvents, or capture technologies that do not use solvents, *e.g.,* membranes, sorbents. A number of technology providers have solvents that are commercially available, as detailed in section VII.C.1.a.i.(B)(3) of this preamble. In addition, a 2022 DOE carbon capture supply chain assessment concluded that common amines used in carbon capture have robust and resilient supply chains that could be rapidly scaled, with low supply chain risk associated with the main inputs for scale-up. See U.S. Department of Energy (DOE). Supply Chain Deep Dive Assessment: Carbon Capture, Transport & Storage. *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf*.

[604] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits*.

[605] Ibid.

[606] SaskPower, ''SaskPower CCS.'' *https://unfccc.int/files/bodies/awg/application/pdf/01_saskatchewan_environment_micheal_monea.pdf*. For corroboration, we note similar employment numbers for two EPAct-05 assisted projects: Petra Nova estimated it would need approximately 1,100 construction-related jobs and up to 20 jobs for ongoing operations. National Energy Technology Laboratory and U.S. Department of Energy. W.A. Parish Post-Combustion CO2 Capture and Sequestration Project, Final Environmental Impact Statement. *https://www.energy.gov/sites/default/files/EIS-0473-FEIS-Summary-2013_1.pdf*. Project Tundra projects a peak labor force of 600 to 700. National Energy Technology Laboratory and U.S. Department of Energy. Draft Environmental Assessment for North Dakota CarbonSAFE: Project Tundra. *https://www.energy.gov/sites/default/files/2023-08/draft-ea-2197-nd-carbonsafe-chapters-2023-08.pdf*.

[607] For the purposes of evaluating the actual workforce and resources necessary for installation of CCS, the five-year assumption in the DOE memo is reasonable. The representative timeline for CCS includes an about 3-year period for construction activities (including site work, construction, and startup and testing) across the components of CCS (capture, pipeline, and sequestration), beginning at the end of 2028. Many sources are well positioned to install CCS, having already completed feasibility work, FEED studies, and/or permitting, and could thereby reasonably start construction activities (still 3-years in duration) by the beginning of 2028 or earlier and, as a practical matter, would likely do so notwithstanding the requirements of this rule

Continued

a subset of coal power plants. The memorandum further estimates that 116,200 to 174,300 average annual jobs would likely be needed if CCS were deployed at all coal-fired EGUs that currently have no firm commitment to retire or convert to natural gas by 2040.[608] For comparison, the DOE memorandum further categorizes potential workforce needs by occupation, and estimates 11,420 to 27,890 annual jobs for construction trade workers, while the U.S. Energy and Employment Report estimates that electric power generation and fuels accounted for more than 292,000 construction jobs in 2022, which is an order of magnitude greater than the potential workforce needs for CCS deployment under this rule. Overall energy-related construction activities across the entire energy industry accounted for nearly 2 million jobs, or 25 percent of all construction jobs in 2022, indicating that there is a very large pool of workers potentially available.[609]

As noted in section VII.C.1.a.i(F), the EPA determined that the population of sources without announced plans to cease operation or discontinue coal-firing by 2039, and that is therefore potentially subject to a CCS BSER, is not more than 81 GW, as indicated in the final TSD, *Power Sector Trends.* The DOE CCS Commodity Materials and Workforce Memos evaluated material resource and workforce needs for a similar capacity (about 73 GW), and determined that the resources and workforce available are more than sufficient, in most cases by an order of magnitude. Considering these factors, and the similar scale of the population of sources considered, the EPA therefore concludes that the workforce and resources available are more than sufficient to meet the demands of coal-fired steam generating units potentially subject to a CCS BSER.

(H) Determination That CCS Is ''Adequately Demonstrated''

As discussed in detail in section V.C.2.b, pursuant to the text, context, legislative history, and judicial precedent interpreting CAA section 111(a)(1), a technology is ''adequately demonstrated'' if there is sufficient evidence that the EPA may reasonably conclude that a source that applies the technology will be able to achieve the associated standard of performance under the reasonably expected operating circumstances. Specifically, an adequately demonstrated standard of performance may reflect the EPA's reasonable expectation of what that particular system will achieve, based on analysis of available data from individual commercial scale sources, and, if necessary, identifying specific available technological improvements that are expected to improve performance.[610] The law is clear in establishing that at the time a section 111 rule is promulgated, the system that the EPA establishes as BSER need not be in widespread use. Instead, the EPA's responsibility is to determine that the demonstrated technology can be implemented at the necessary scale in a reasonable period of time, and to base its requirements on this understanding.

In this case, the EPA acknowledged in the proposed rule, and reaffirms now, that sources will require some amount of time to install CCS. Installing CCS requires the building of capture facilities and pipelines to transport captured CO_2 to sequestration sites, and the development of sequestration sites. This is true for both existing coal plants, which will need to retrofit CCS, and new gas plants, which must incorporate CCS into their construction planning. As the EPA explained at proposal, D.C. Circuit caselaw supports this approach.[611] Moreover, the EPA has determined that there will be sufficient resources for all coal-fired power plants that are reasonably expected to be operating as of January 1, 2039, to install CCS. Nothing in the comments alters the EPA's view of the relevant legal requirements related to the EPA's determination of time necessary to allow for adoption of the system.

With all of the above in mind, the preceding sections show that CCS technology with 90 percent capture is clearly adequately demonstrated for coal-fired steam generating units, that the 90 percent standard is achievable,[612] and that it is reasonable for the EPA to determine that CCS can be deployed at the necessary scale in the compliance timeframe.

(1) EPAct05

In the proposal, the EPA noted that in the 2015 NSPS, the EPA had considered coal-fired industrial projects that had installed at least some components of CCS technology. In doing so, the EPA recognized that some of those projects had received assistance in the form of grants, loan guarantees, and Federal tax credits for investment in ''clean coal technology,'' under provisions of the Energy Policy Act of 2005 (''EPAct05''). See 80 FR 64541–42 (October 23, 2015). (The EPA refers to projects that received assistance under that legislation as ''EPAct05-assisted projects.'') The EPA further recognized that the EPAct05 included provisions that constrained how the EPA could rely on EPAct05-assisted projects in determining whether technology is adequately demonstrated for the purposes of CAA section 111.[613]

given the strong economic incentives provided by the tax credit. The representative timeline also makes conservative assumptions about the pre-construction activities for pipelines and sequestration, and for many sources construction of those components could occur earlier. Finally, to provide greater regulatory certainty and incentivize the installation of controls, the EPA is finalizing a limited one-year compliance date extension mechanism for certain circumstances as detailed in section X.C.1.d of the preamble, and it would also be reasonable to assume that, in practice, some sources use that mechanism. Considering these factors, evaluating workforce and resource requirements over a five-year period is reasonable.

[608] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits.*

[609] U.S. Department of Energy. United States Energy & Employment Report 2023. *https://www.energy.gov/sites/default/files/2023-06/2023%20USEER%20REPORT-v2.pdf.*

[610] A line of cases establishes that the EPA may extrapolate based on its findings and project technological improvements in a variety of ways. First, the EPA may reasonably extrapolate from testing results to predict a lower emissions rate than has been regularly achieved in testing. *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973). Second, the EPA may forecast technological improvements allowing a lower emissions rate or effective control at larger plants than those previously subject to testing, provided the agency has adequate knowledge about the needed changes to make a reasonable prediction. *See Sierra Club* v. *Costle* 657 F.2d 298 (1981). Third, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different, related, source. *See Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[611] There, EPA cited *Portland Cement* v. *Ruckelshaus,* for the proposition that ''D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the 'adequately demonstrated' criterion—even if the controls require some amount of 'lead time,' which the court has defined as 'the time in which the technology will have to be available.' '' *See New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule,* 88 FR 33240, 33289 (May 23, 2023) (quoting *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973)).

[612] The concepts of ''adequately demonstrated'' and ''achievable'' are closely related. As the D.C. Circuit explained in *Essex Chem. Corp.* v. *Ruckelshaus,* ''[i]t is the *system* which must be adequately demonstrated and the *standard* which must be achievable.'' 486 F.2d 427, 433 (1973).

[613] The relevant EPAct05 provisions include the following: Section 402(i) of the EPAct05, codified at 42 U.S.C. 15962(a), provides as follows: ''No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .'' IRC section 48A(g), as added by EPAct05

In the 2015 NSPS, the EPA went on to provide a legal interpretation of those constraints. Under that legal interpretation, ''these provisions [in the EPAct05] . . . preclude the EPA from relying solely on the experience of facilities that received [EPAct05] assistance, but [do] not . . . preclude the EPA from relying on the experience of such facilities in conjunction with other information.'' [614] *Id.* at 64541–42. In this action, the EPA is adhering to the interpretation of these provisions that it announced in the 2015 NSPS.

Some commenters criticized the legal interpretation that the EPA advanced in the 2015 NSPS, and others supported the interpretation. The EPA has responded to these comments in the Response to Comments Document, available in the docket for this rulemaking.

ii. Costs

The EPA has analyzed the costs of CCS for existing coal-fired long-term steam generating units, including costs for CO_2 capture, transport, and sequestration. The EPA has determined costs of CCS for these sources are reasonable. The EPA also evaluated costs assuming shorter amortization periods. As elsewhere in this section of the preamble, costs are presented in 2019 dollars. In sum, the costs of CCS are reasonable under a variety of metrics. The costs of CCS are reasonable as compared to the costs of other controls that the EPA has required for these sources. And the costs of CCS are reasonable when looking to the dollars per ton of CO_2 reduced. The reasonableness of CCS as an emission control is further reinforced by the fact that some sources are projected to install CCS even in the absence of any EPA rule addressing CO_2 emissions—11 GW of coal-fired EGUs install CCS in the modeling base case.

Specifically, the EPA assessed the average cost of CCS for the fleet of coal-fired steam generating units with no announced retirement or gas conversion prior to 2039. In evaluating costs, the EPA accounts for the IRC section 45Q tax credit of $85/metric ton (assumes prevailing wage and apprenticeship requirements are met), a detailed discussion of which is provided in section VII.C.1.a.ii(C) of this preamble. The EPA also accounts for increases in utilization that will occur for units that apply CCS due to the incentives provided by the IRC section 45Q tax credit. In other words, because the IRC section 45Q tax credit provides a significant economic benefit, sources that apply CCS will have a strong economic incentive to increase utilization and run at higher capacity factors than occurred historically. This assumption is confirmed by the modeling, which projects that sources that install CCS run at a high capacity factor—generally, about 80 percent or even higher. The EPA notes that the NETL Baseline study assumes 85 percent as the default capacity factor assumption for coal CCS retrofits, noting that coal plants in market conditions supporting baseload operation have demonstrated the ability to operate at annual capacity factors of 85 percent or higher.[615] This assumption is also supported by observations of wind generators who receive the IRC section 45 production tax credit who continue to operate even during periods of negative power prices.[616] Therefore, the EPA assessed the costs for CCS retrofitted to existing coal-fired steam generating units assuming an 80 percent annual capacity factor. Assuming an 80 percent capacity factor and 12-year amortization period,[617] the average costs of CCS for the fleet are −$5/ton of CO_2 reduced or −$4/MWh of generation. Assuming at least a 12-year amortization period is reasonable because any unit that installs CCS and seeks to maximize its profitability will be incentivized to recoup the full value of the 12-year tax credit.

Therefore for long-term coal-fired steam generating units—ones that operate after January 1, 2039—the costs of CCS are similar or better than the representative costs of controls detailed in section VII.C.1.a.ii(D) of this preamble (*i.e.,* costs for SCRs and FGDs on EGUs of $10.60 to $18.50/MWh and the costs in the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category of $98/ton of CO_2e reduced (80 FR 56627; September 18, 2015)).

The EPA also evaluated the costs for shorter amortization periods, considering the $/MWh and $/ton metrics, as well as other cost indicators, as described in section VII.C.1.a.ii.(D). Specifically, with an initial compliance date of January 1, 2032, sources operating through the end of 2039 have at least 8 years to amortize costs. For an 80 percent capacity factor and an 8-year amortization period, the average costs of CCS for the fleet are $19/ton of CO_2 reduced or $18/MWh of generation; these costs are comparable to those costs that the EPA has previously determined to be reasonable. Sources operating through the end of 2040, 2041, and beyond (*i.e.,* sources with 9, 10, or more years to amortize the costs of CCS) have even more favorable average costs per MWh and per ton of CO_2 reduced. Sources ceasing operation by January 1, 2039, have 7 years to amortize costs. For an 80 percent capacity factor and a 7-year amortization period, the fleet average costs are $29/ton of CO_2 reduced or $28/MWh of generation; these average costs are less comparable on a $/MWh of generation basis to those costs the EPA has previously determined to be reasonable, but substantially lower than costs the EPA has previously determined to be reasonable on a $/ton of CO_2 reduced basis. The EPA further notes that the costs presented are average costs for the fleet. For a substantial amount of capacity, costs assuming a 7-year amortization period are comparable to those costs the EPA has previously determined to be reasonable on both a $/MWh basis (*i.e.,* less than $18.50/MWh) and a $/ton basis (*i.e.* less than $98/ton CO2e),[618] and the EPA concludes that a substantial amount of capacity can install CCS at reasonable cost with a 7-year amortization

1307(b), provides as follows: ''No use of technology (or level of emission reduction solely by reason of the use of the technology), and no achievement of any emission reduction by the demonstration of any technology or performance level, by or at one or more facilities with respect to which a credit is allowed under this section, shall be considered to indicate that the technology or performance level is adequately demonstrated [ ] for purposes of section 111 of the Clean Air Act. . . .'' Section 421(a) states: ''No technology, or level of emission reduction, shall be treated as adequately demonstrated for purpose [*sic*] of section 7411 of this title, . . . solely by reason of the use of such technology, or the achievement of such emission reduction, by one or more facilities receiving assistance under section 13572(a)(1) of this title.''

[614] In the 2015 NSPS, the EPA adopted several other legal interpretations of these EPAct05 provisions as well. See 80 FR 64541 (October 23, 2015).

[615] See Exhibit 2–18. *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVolume1BituminousCoalAndNaturalGasToElectricity_101422.pdf.*

[616] If those generators were not receiving the tax credit, they otherwise would cease producing power during those periods and result in a lower overall capacity factor. As noted by EIA, ''Wind plants can offer negative prices because of the revenue stream that results from the federal production tax credit, which generates tax benefits whenever the wind plant is producing electricity, and payments from state renewable portfolio or financial incentive programs. These alternative revenue streams make it possible for wind generators to offer their wind power into the wholesale electricity market at prices lower than other generators, and even at negative prices.'' *https://www.eia.gov/todayinenergy/detail.php?id=16831.*

[617] A 12-year amortization period is consistent with the period of time during which the IRC section 45Q tax credit can be claimed.

[618] See the final TSD, *GHG Mitigation Measures for Steam Generating Units* for additional details.

period.[619] Considering that a significant number of sources can cost reasonably install CCS even assuming a 7-year amortization period, the EPA concludes that sources operating in 2039 should be subject to a CCS BSER,[620] and for this reason, is finalizing the date of January 1, 2039 as the dividing line between the medium-term and long-term subcategories. Moreover, the EPA underscores that given the strong economic incentives of the IRC section 45Q tax credit, sources that install CCS will have strong economic incentives to operate at high capacity for the full 12 years that the tax credit is available.

As discussed in the RTC section 2.16, the EPA has also examined the reasonableness of the costs of this rule in additional ways: considering the total annual costs of the rule as compared to past CAA rules for the electricity sector and as compared to the industry's annual revenues and annual capital expenditures, and considering the effects of this rule on electricity prices. Taking all of these into consideration, in addition to the cost metrics just discussed, the EPA concludes that, in general, the costs of CCS are reasonable for sources operating after January 1, 2039.

(A) Capture Costs

The EPA developed an independent engineering cost assessment for CCS retrofits, with support from Sargent and Lundy.[621] The EPA cost analysis assumes installation of one CO_2 capture plant for each coal-fired EGU, and that sources without SO_2 controls (FGD) or NO_X controls (specifically, selective catalytic reduction—SCR; or selective non-catalytic reduction—SNCR) add a wet FGD and/or SCR.[622]

(B) CO_2 Transport and Sequestration Costs

To calculate the costs of CCS for coal-fired steam generating units for purposes of determining BSER as well as for EPA modeling, the EPA relied on transportation and storage costs consistent with the cost of transporting and storing CO_2 from each power plant to the nearest saline reservoir.[623] For a power plant composed of multiple coal-fired EGUs, the EPA's cost analysis assumes installation and operation of a single, common CO_2 pipeline.

The EPA notes that NETL has also developed costs for transport and storage. NETL's ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies'' provides an estimation of transport costs based on the CO_2 Transport Cost Model.[624] The CO_2 Transport Cost Model estimates costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operations and maintenance costs.[625]

NETL's Quality Guidelines also provide an estimate of sequestration costs. These costs reflect the cost of site screening and evaluation, permitting and construction costs, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection. Permitting and construction costs also reflect the regulatory requirements of the UIC Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations. NETL calculates these sequestration costs on the basis of generic plant locations in the Midwest, Texas, North Dakota, and Montana, as described in the NETL energy system studies that utilize the coal found in Illinois, East Texas, Williston, and Powder River basins.[626]

There are two primary cost drivers for a CO_2 sequestration project: the rate of injection of the CO_2 into the reservoir and the areal extent of the CO_2 plume in the reservoir. The rate of injection depends, in part, on the thickness of the reservoir and its permeability. Thick, permeable reservoirs provide for better injection and fewer injection wells. The areal extent of the CO_2 plume depends on the sequestration capacity of the reservoir. Thick, porous reservoirs with a good sequestration coefficient will present a small areal extent for the CO_2 plume and have a smaller monitoring footprint, resulting in lower monitoring costs. NETL's Quality Guidelines model costs for a given cumulative sequestration potential.[627]

In addition, provisions in the IIJA and IRA are expected to significantly increase the CO_2 pipeline infrastructure and development of sequestration sites, which, in turn, are expected to result in further cost reductions for the application of CCS at new combined cycle EGUs. The IIJA establishes a new Carbon Dioxide Transportation Infrastructure Finance and Innovation program to provide direct loans, loan guarantees, and grants to CO_2 infrastructure projects, such as pipelines, rail transport, ships and barges.[628] The IIJA also establishes a new Regional Direct Air Capture Hubs program that includes funds to support four large-scale, regional direct air capture hubs and more broadly support projects that could be developed into a regional or inter-regional network to facilitate sequestration or utilization.[629] DOE is additionally implementing IIJA section 40305 (Carbon Storage Validation and Testing) through its CarbonSAFE initiative, which aims to further develop geographically widespread, commercial-scale, safe sequestration.[630] The IRA increases and

[619] As indicated in section 4.7.5 of the final TSD, *Greenhouse Gas Mitigation Measures for Steam Generating Units,* 24 percent of all coal-fired steam generating units in the long-term subcategory would have CCS costs below both $18.50/MWh and $98/ton of CO_2 with a 7-year amortization period (Table 11), and that amount increases to 40 percent for those coal-fired units that, in light of their age and efficiency, are most likely to operate in the long term (and thus be subject to the CCS-based standards of performance) (Table 12). In addition, of the 9 units in the NEEDS data base that have announced plans to retire in 2039, and that therefore would have a 7-year amortization period if they installed CCS by January 1, 2032, 6 would have costs below both $18.50/MWh and $98/ton of CO_2.

[620] The EPA determines the BSER based on considering information on the statutory factors, including cost, on a source category or subcategory basis. However, there may be particular sources for which, based on source-specific considerations, the cost of CCS is fundamentally different from the costs the EPA considered in making its BSER determination. If such a fundamental difference makes it unreasonable for a particular source to achieve the degree of emission limitation associated with implementing CCS with 90 percent capture, a state may provide a less stringent standard of performance (and/or longer compliance schedule, if applicable) for that source pursuant to the RULOF provisions. See section X.C.2 of this preamble for further discussion.

[621] Detailed cost information, assessment of technology options, and demonstration of cost reasonableness can be found in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[622] Whether an FGD and SCR or controls with lower costs are necessary for flue gas pretreatment prior to the CO_2 capture process will in practice depend on the flue gas conditions of the source.

[623] For additional details on CO_2 transport and storage costs, see the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[624] Grant, T., *et al.* (2019). ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies.'' National Energy Technology Laboratory. *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[625] Grant, T., *et al.* ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies.'' National Energy Technology Laboratory. 2019. *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[626] National Energy Technology Laboratory (NETL). (2017). ''FE/NETL CO_2 Saline Storage Cost Model (2017),'' U.S. Department of Energy, DOE/NETL–2018–1871. *https://netl.doe.gov/energy-analysis/details?id=2403.*

[627] Details on CO_2 transportation and sequestration costs can be found in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

[628] Department of Energy. ''Biden-Harris Administration Announces $2 Billion from Bipartisan Infrastructure Law to Finance Carbon Dioxide Transportation Infrastructure.'' (2022). *https://www.energy.gov/articles/biden-harris-administration-announces-2-billion-bipartisan-infrastructure-law-finance.*

[629] Department of Energy. ''Regional Direct Air Capture Hubs.'' (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[630] For more information, see the NETL announcement. *https://www.netl.doe.gov/node/12405.*

extends the IRC section 45Q tax credit, discussed next.

(C) IRC Section 45Q Tax Credit

In determining the cost of CCS, the EPA is taking into account the tax credit provided under IRC section 45Q, as revised by the IRA. The tax credit is available at $85/metric ton ($77/ton) and offsets a significant portion of the capture, transport, and sequestration costs noted above.

Several other aspects of the tax credit should be noted. A tax credit offsets tax liability dollar for dollar up to the amount of the taxpayer's tax liability. Any credits in excess of the taxpayer's liability are eligible to be carried back (3 years in the case of IRC section 45Q) and then carried forward up to 20 years.[631]As noted above, the IRA also enabled additional methods to monetize tax credits in the event the taxpayer does not have sufficient tax liability, such as through credit transfer.

The EPA has determined that it is likely that EGUs installing CCS will meet the 45Q prevailing wage and apprenticeship requirements. First, the requirements provide a significant economic incentive, increasing the value of the 45Q credit by five times over the base value of the credit available if the prevailing wage and apprenticeship requirements are not met. This provides a significant incentive to meet the requirements. Second, the increased cost of meeting the requirements is likely significantly less than the increase in credit value. A recent EPRI assessment found meeting the requirements for other types of power generation projects resulted in significant savings across projects,[632] and other studies indicate prevailing wage laws and requirements for construction projects in general do not significantly affect overall construction costs.[633] The EPA expects a similar dynamic for 45Q projects. Third, the use of registered apprenticeship programs for training new employees is generally well-established in the electric power generation sector, and apprenticeship programs are widely available to generate additional trained workers in this field.[634] The overall U.S. apprentice market has more than doubled between 2014 and 2023, growing at an average annual rate of more than 7 percent.[635] Additional programs support the skilled construction trade workforce required for CCS implementation and maintenance.[636]

As discussed in section V.C.2.c of this preamble, CAA section 111(a)(1) is clear that the cost that the Administrator must take into account in determining the BSER is the cost of the controls to the source. It is reasonable to take the tax credit into account because it reduces the cost of the controls to the source, which has a significant effect on the actual cost of installing and operating CCS. In addition, all sources that install CCS to meet the requirements of these final actions are eligible for the tax credit. The legislative history of the IRA makes clear that Congress was well aware that the EPA may promulgate rulemaking under CAA section 111 based on CCS and the utility of the tax credit in reducing the costs of CCUS (*i.e.,* CCS). Rep. Frank Pallone, the chair of the House Energy & Commerce Committee, included a statement in the Congressional Record when the House adopted the IRA in which he explained: ''The tax credit[ ] for CCUS . . . included in this Act may also figure into CAA Section 111 GHG regulations for new and existing industrial sources[.] . . . Congress anticipates that EPA may consider CCUS . . . as [a] candidate[ ] for BSER for electric generating plants . . . . Further, Congress anticipates that EPA may consider the impact of the CCUS . . . tax credit[ ] in lowering the costs of [that] measure[ ].'' 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone).

In the 2015 NSPS, in which the EPA determined partial CCS to be the BSER for GHGs from new coal-fired steam generating EGUs, the EPA recognized that the IRC section 45Q tax credit or other tax incentives could factor into the cost of the controls to the sources. Specifically, the EPA calculated the cost of partial CCS on the basis of cost calculations from NETL, which included ''a range of assumptions including the projected capital costs, the cost of financing the project, the fixed and variable O&M costs, the projected fuel costs, and incorporation of any incentives such as tax credits or favorable financing that may be available to the project developer.'' 80 FR 64570 (October 23, 2015).[637]

Similarly, in the 2015 NSPS, the EPA also recognized that revenues from utilizing captured CO_2 for EOR would reduce the cost of CCS to the sources, although the EPA did not account for potential EOR revenues for purposes of determining the BSER. *Id.* At 64563–64. In other rules, the EPA has considered revenues from sale of the by-products of emission controls to affect the costs of the emission controls. For example, in the 2016 Oil and Gas Methane Rule, the EPA determined that certain control requirements would reduce natural gas leaks and therefore result in the collection of recovered natural gas that could be sold; and the EPA further determined that revenues from the sale of the recovered natural gas reduces the cost of controls. See 81 FR 35824 (June 3, 2016). The EPA made the same determination in the 2024 Oil and Gas Methane Rule. See 89 FR 16820, 16865 (May 7, 2024). In a 2011 action concerning a regional haze SIP, the EPA recognized that a NO_X control would alter the chemical composition of fly ash that the source had previously sold, so that it could no longer be sold; and as a result, the EPA further determined that the cost of the NO_X control should include the foregone revenues from the fly ash sales. 76 FR 58570, 58603 (September 21, 2011). In the 2016 emission guidelines for landfill gas from municipal solid waste landfills, the EPA reduced the costs of controls by accounting for revenue from the sale of electricity produced from the landfill gas collected through the controls. 81 FR 59276, 19679 (August 29, 2016).

The amount of the IRC section 45Q tax credit that the EPA is taking into account is $85/metric ton for CO_2 that is captured and geologically stored. This amount is available to the affected source as long as it meets the prevailing wage and apprenticeship requirements of IRC section 45Q(h)(3)–(4). The legislative history to the IRA specifically stated that when the EPA considers CCS as the BSER for GHG emissions from industrial sources in CAA section 111 rulemaking, the EPA should determine the cost of CCS by assuming that the sources would meet those prevailing wage and apprenticeship requirements. 168 Cong. Rec. E879 (August 26, 2022) (statement of Rep. Frank Pallone). If prevailing wage and apprenticeship requirements are not met, the value of the IRC section 45Q tax credit falls to $17/metric ton. The substantially higher credit available provides a considerable incentive to meeting the prevailing wage and apprenticeship requirements.

[631] IRC section 39.

[632] *https://www.epri.com/research/products/000000003002027328.*

[633] *https://journals.sagepub.com/doi/abs/10.1177/0160449X18766398.*

[634] DOE. Workforce Analysis of Existing Coal Carbon Capture Retrofits. *https://www.energy.gov/policy/articles/workforce-analysis-existing-coal-carbon-capture-retrofits.*

[635] *https://www.apprenticeship.gov/data-and-statistics.*

[636] *https://www.apprenticeship.gov/partner-finder.*

[637] In fact, because of limits on the availability of the IRC section 45Q tax credit at the time of the 2015 NSPS, the EPA did not factor it into the cost calculation for partial CCS. 80 FR 64558–64 (October 23, 2015).

Therefore, the EPA assumes that investors maximize the value of the IRC section 45Q tax credit at $85/metric ton by meeting those requirements.

(D) Comparison to Other Costs of Controls and Other Measures of Cost Reasonableness

In assessing cost reasonableness for the BSER determination for this rule, the EPA looks at a range of cost information. As discussed in Chapter 2 of the RTC, the EPA considered the total annual costs of the rule as compared to past CAA rules for the electricity sector and as compared to the industry's annual revenues and annual capital expenditures, and considered the effects of this rule on electricity prices.

For each of the BSER determinations, the EPA also considers cost metrics that it has historically considered in assessing costs to compare the costs of GHG control measures to control costs that the EPA has previously determined to be reasonable. This includes comparison to the costs of controls at EGUs for other air pollutants, such as SO_2 and NO_X, and costs of controls for GHGs in other industries. Based on these costs, the EPA has developed two metrics for assessing the cost reasonableness of controls: the increase in cost of electricity due to controls, measured in $/MWh, and the control costs of removing a ton of pollutant, measured in $/ton CO_2e. The costs presented in this section of the preamble are in 2019 dollars.[638]

In different rulemakings, the EPA has required many coal-fired steam generating units to install and operate flue gas desulfurization (FGD) equipment—that is, wet or dry scrubbers—to reduce their SO_2 emissions or SCR to reduce their NO_X emissions. The EPA compares these control costs across technologies—steam generating units and combustion turbines—because these costs are indicative of what is reasonable for the power sector in general. The facts that the EPA required these controls in prior rules, and that many EGUs subsequently installed and operated these controls, provide evidence that these costs are reasonable, and as a result, the cost of these controls provides a benchmark to assess the reasonableness of the costs of the controls in this preamble. In the 2011 CSAPR (76 FR 48208; August 8, 2011), the EPA estimated the annualized costs to install and operate wet FGD retrofits on existing coal-fired steam generating units. Using those same cost equations and assumptions (*i.e.,* a 63 percent annual capacity factor—the average value in 2011) for retrofitting wet FGD on a representative 700 to 300 MW coal-fired steam generating unit results in annualized costs of $14.80 to $18.50/MWh of generation, respectively.[639] In the Good Neighbor Plan for the 2015 Ozone NAAQS (2023 GNP), 88 FR 36654 (June 5, 2023), the EPA estimated the annualized costs to install and operate SCR retrofits on existing coal-fired steam generating units. Using those same cost equations and assumptions (including a 56 percent annual capacity factor—a representative value in that rulemaking) to retrofit SCR on a representative 700 to 300 MW coal-fired steam generating unit results in annualized costs of $10.60 to $11.80/MWh of generation, respectively.[640]

The EPA also compares costs to the costs for GHG controls in rulemakings for other industries. In the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category, the EPA found the costs of reducing methane emissions of $2,447/ton to be reasonable (80 FR 56627; September 18, 2015).[641] Converted to a ton of CO_2e reduced basis, those costs are expressed as $98/ton of CO_2e reduced.[642]

The EPA does not consider either of these metrics, $18.50/MWh and $98/ton of CO_2e, to be bright line standards that distinguish between levels of control costs that are reasonable and levels that are unreasonable. But they do usefully indicate that control costs that are generally consistent with those levels of control costs should be considered reasonable. The EPA has required controls with comparable costs in prior rules for the electric power industry and the industry has successfully complied with those rules by installing and operating the applicable controls. In the case of the $/ton metric, the EPA has required other industries—specifically, the oil and gas industry—to reduce their climate pollution at this level of cost-effectiveness. In this rulemaking, the costs of the controls that the EPA identifies as the BSER generally match up well against both of these $/MWh and $/ton metrics for the affected subcategories of sources. And looking broadly at the range of cost information and these cost metrics, the EPA concludes that the costs of these rules are reasonable.

(E) Comparison to Costs for CCS in Prior Rulemakings

In the CPP and ACE Rule, the EPA determined that CCS did not qualify as the BSER due to cost considerations. Two key developments have led the EPA to reevaluate this conclusion: the costs of CCS technology have fallen and the extension and increase in the IRC section 45Q tax credit, as included in the IRA, in effect provide a significant stream of revenue for sequestered CO_2 emissions. The CPP and ACE Rule relied on a 2015 NETL report estimating the cost of CCS. NETL has issued updated reports to incorporate the latest information available, most recently in 2022, which show significant cost reductions. The 2015 report estimated incremental levelized cost of CCS at a new pulverized coal facility relative to a new facility without CCS at $74/MWh (2022$),[643] while the 2022 report estimated incremental levelized cost at $44/MWh (2022$).[644] Additionally, the IRA increased the IRC section 45Q tax credit from $50/metric ton to $85/metric ton (and, in the case of EOR or certain industrial uses, from $35/metric ton to $60/metric ton), assuming prevailing wage and apprenticeship conditions are met. The IRA also enhanced the realized value of the tax credit through the elective pay (informally known as direct pay) and transferability monetization options described in section IV.E.1. The combination of lower costs and higher tax credits significantly improves the cost reasonableness of CCS for purposes

[638] The EPA used the NETL Baseline Report costs directly for the combustion turbine model plant BSER analysis. Even though these costs are in 2018 dollars, the adjustment to 2019 dollars (1.018 using the U.S. GDP Implicit Price Deflator) is well within the uncertainty range of the report and the minor adjustment would not impact the EPA's BSER determination.

[639] For additional details, see *https://www.epa.gov/power-sector-modeling/documentation-integrated-planning-model-ipm-base-case-v410.*

[640] For additional details, see *https://www.epa.gov/system/files/documents/2023-01/Updated%20Summer%202021%20Reference%20Case%20Incremental%20Documentation%20for%20the%202015%20Ozone%20NAAQS%20Actions_0.pdf.*

[641] The EPA finalized the 2016 NSPS GHGs for the Crude Oil and Natural Gas source category at 81 FR 35824 (June 3, 2016). The EPA included cost information in the proposed rulemaking, at 80 FR 56627 (September 18, 2015).

[642] Based on the 100-year global warming potential for methane of 25 used in the GHGRP (40 CFR 98 Subpart A, table A–1).

[643] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 3 (July 2015). *Note:* The EPA adjusted reported costs to reflect $2022. *https://www.netl.doe.gov/projects/files/CostandPerformanceBaselinefor FossilEnergyPlantsVolume1aBit CoalPCandNaturalGastoElectRev3_070615.pdf.*

[644] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022). *Note:* The EPA adjusted reported costs to reflect $2022. *https://netl.doe.gov/projects/files/CostAndPerformanceBaselineFor FossilEnergyPlantsVolume1Bituminous CoalAndNaturalGasToElectricity_101422.pdf.*

of determining whether it qualifies as the BSER.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

The EPA considered non-GHG emissions impacts, the water use impacts, the transport and sequestration of captured CO_2, and energy requirements resulting from CCS for steam generating units. As discussed below, where the EPA has found potential for localized adverse consequences related to non-air quality health and environmental impacts or energy requirements, the EPA also finds that protections are in place to mitigate those risks. Because the non-air quality health and environmental impacts are closely related to the energy requirements, we discuss the latter first.

(A) Energy Requirements

For a steam generating unit with 90 percent amine-based CO_2 capture, parasitic/auxiliary energy demand increases and the net power output decreases. In particular, the solvent regeneration process requires heat in the form of steam and CO_2 compression requires a large amount of electricity. Heat and power for the CO_2 capture equipment can be provided either by using the steam and electricity produced by the steam generating unit or by an auxiliary cogeneration unit. However, any auxiliary source of heat and power is part of the ''designated facility,'' along with the steam generating unit. The standards of performance apply to the designated facility. Thus, any CO_2 emissions from the connected auxiliary equipment need to be captured or they will increase the facility's emission rate.

Using integrated heat and power can reduce the capacity (*i.e.,* the amount of electricity that a unit can distribute to the grid) of an approximately 474 MW-net (501 MW-gross) coal-fired steam generating unit without CCS to approximately 425 MW-net with CCS and contributes to a reduction in net efficiency of 23 percent.[645] For retrofits of CCS on existing sources, the ductwork for flue gas and piping for heat integration to overcome potential spatial constraints are a component of efficiency reduction. The EPA notes that slightly greater efficiency reductions than in the 2016 NETL retrofit report are assumed for the BSER cost analyses, as detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket. Despite decreases in efficiency, IRC section 45Q tax credit provides an incentive for increased generation with full operation of CCS because the amount of revenue from the tax credit is based on the amount of captured and sequestered CO_2 emissions and not the amount of electricity generated. In this final action, the Agency considers the energy penalty to not be unreasonable and to be relatively minor compared to the benefits in GHG reduction of CCS.

(B) Non-GHG Emissions

As a part of considering the non-air quality health and environmental impacts of CCS, the EPA considered the potential non-GHG emission impacts of CO_2 capture. The EPA recognizes that amine-based CO_2 capture can, under some circumstances, result in the increase in emission of certain co-pollutants at a coal-fired steam generating unit. However, there are protections in place that can mitigate these impacts. For example, as discussed below, CCS retrofit projects with co-pollutant increases may be subject to preconstruction permitting under the New Source Review (NSR) program, which could require the source to adopt emission limitations based on applicable NSR requirements. Sources obtaining major NSR permits would be required to either apply Lowest Achievable Emission Rate (LAER) and fully offset any anticipated increases in criteria pollutant emissions (for their nonattainment pollutants) or apply Best Available Control Technology (BACT) and demonstrate that its emissions of criteria pollutants will not cause or contribute to a violation of applicable National Ambient Air Quality Standards (for their attainment pollutants).[646] The EPA expects facility owners, states, permitting authorities, and other responsible parties will use these protections to address co-pollutant impacts in situations where individual units use CCS to comply with these emission guidelines.

The EPA also expects that the meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders, including community members who might be adversely impacted by non-GHG pollutants, will have an opportunity to raise this concern with states and permitting authorities. Additionally, state permitting authorities are, in general, required to provide notice and an opportunity for public comment on construction projects that require NSR permits. This provides additional opportunities for affected stakeholders to engage in that process, and it is the EPA's expectation that the responsible authorities will consider these concerns and take full advantage of existing protections. Moreover, the EPA through its regional offices is committed to thoroughly review draft NSR permits associated with CO_2 capture projects and provide comments as necessary to state permitting authorities to address any concerns or questions with regard to the draft permit's consideration and treatment of non-GHG pollutants.

In the following discussion, the EPA describes the potential emissions of non-GHG pollutants resulting from installation and operation of CO_2 capture plants, the protections in place such as the controls and processes for mitigating those emissions, as well as regulations and permitting that may require review and implementation of those controls. The EPA first discusses these issues in relation to criteria air pollutants and precursor pollutants (SO_2, NO_X, and PM), and subsequently provides details regarding hazardous air pollutants (HAPs) and volatile organic compounds (VOCs).

Operation of an amine-based CO_2 capture plant on a coal-fired steam generating unit can impact the emission of criteria pollutants from the facility, including SO_2 and PM, as well as precursor pollutants, like NO_X. Sources installing CCS may operate more due to the incentives provided by the IRC section 45Q tax credit, and increased utilization would—all else being equal—result in increases in SO_2, PM, and NO_X. However, certain impacts are mitigated by the flue gas conditioning required by the CO_2 capture process and by other control equipment that the units already have or may need to install to meet other CAA requirements. Substantial flue gas conditioning, particularly to remove SO_2 and PM, is critical to limiting solvent degradation and maintaining reliable operation of the capture plant. To achieve the necessary limits on SO_2 levels in the flue gas for the capture process, steam generating units will need to add an FGD scrubber, if they do not already have one, and will usually need an additional polishing column (*i.e.,* quencher), thereby further reducing the emission of SO_2. A wet FGD column and a polishing column will also reduce the emission rate of PM. Additional improvements in PM removal may also be necessary to reduce the fouling of

[645] DOE/NETL–2016/1796. ''Eliminating the Derate of Carbon Capture Retrofits.'' May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=d335ce79-84ee-4a0b-a27b-c1a64edbb866.*

[646] Section XI.A of this preamble provides additional information on the NSR program and how it relates to the NSPS and emission guidelines.

other components (*e.g.,* heat exchangers) of the capture process, including upgrades to existing PM controls or, where appropriate, the inclusion of various wash stages to limit fly ash carry-over to the CO_2 removal system. Although PM emissions from the steam generating unit may be reduced, PM emissions may occur from cooling towers for those sources using wet cooling for the capture process. For some sources, a WESP may be necessary to limit the amount of aerosols in the flue gas prior to the CO_2 capture process. Reducing the amount of aerosols to the CO_2 absorber will also reduce emissions of the solvent out of the top of the absorber. Controls to limit emission of aerosols installed at the outlet of the absorber could be considered, but could lead to higher pressure drops. Thus, emission increases of SO_2 and PM would be reduced through flue gas conditioning and other system requirements of the CO_2 capture process, and NSR permitting would serve as an added backstop to review remaining SO_2 and PM increases for mitigation.

NO_X emissions can cause solvent degradation and nitrosamine formation, depending on the chemical structure of the solvent. Limits on NO_X levels of the flue gas required to avoid solvent degradation and nitrosamine formation in the CO_2 scrubber vary. For most units, the requisite limits on NO_X levels to assure that the CO_2 capture process functions properly may be met by the existing NO_X combustion controls. Other units may need to install SCR to achieve the required NOx level. Most existing coal-fired steam generating units either already have SCR or will be covered by final Federal Implementation Plan (FIP) requirements regulating interstate transport of NO_X (as ozone precursors) from EGUs. See 88 FR 36654 (June 5, 2023).[647] For units not otherwise required to have SCR, an increase in utilization from a CO_2 capture retrofit could result in increased NO_X emissions at the source that, depending on the quantity of the emissions increase, may trigger major NSR permitting requirements. Under this scenario, the permitting authority may determine that the NSR permit requires the installation of SCR for those units, based on applying the control technology requirements of major NSR. Alternatively, a state could, as part of its state plan, develop enforceable conditions for a source expected to trigger major NSR that would effectively limit the unit's ability to increase its emissions in amounts that would trigger major NSR. Under this scenario, with no major NSR requirements applying due to the limit on the emissions increase, the permitting authority may conclude for the minor NSR permit that installation of SCR is not required for the units and the source is to minimize its NO_X emission increases using other techniques. Finally, a source with some lesser increase in NO_X emissions may not trigger major NSR to begin with and, as with the previous scenario, the permitting authority would determine the NO_X control requirements pursuant to its minor NSR program requirements.

Recognizing that potential emission increases of SO_2, PM, and NO_X from operating a CO_2 capture process are an area of concern for stakeholders, the EPA plans to review and update as needed its guidance on NSR permitting, specifically with respect to BACT determinations for GHG emissions and consideration of co-pollutant increases from sources installing CCS. In its analysis to support this final action, the EPA accounted for controlling these co-pollutant increases by assuming that coal-fired units that install CCS would be required to install SCR and/or FGD if they do not already have those controls installed. The costs of these controls are included in the total program compliance cost estimates through IPM modeling, as well as in the BSER cost calculations.

An amine-based CO_2 capture plant can also impact emissions of HAP and VOC (as an ozone precursor) from the coal-fired steam generating unit. Degradation of the solvent can produce HAP, and organic HAP and amine solvent emissions from the absorber would contribute to VOC emissions out of the top of the CO_2 absorber. A conventional multistage water or acid wash and mist eliminator (demister) at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.,* nitrosamine) emissions.[648] [649] The DOE's Carbon Management Pathway report notes that monitoring and emission controls for such degradation products are currently part of standard operating procedures for amine-based CO_2 capture systems.[650] Depending on the solvent properties, different amounts of aldehydes including acetaldehyde and formaldehyde may form through oxidative processes, contributing to total HAP and VOC emissions. While a water wash or acid wash can be effective at limiting emission of amines, a separate system of controls would be required to reduce aldehyde emissions; however, the low temperature and likely high water vapor content of the gas emitted out of absorber may limit the applicability of catalytic or thermal oxidation. Other controls (*e.g.,* electrochemical, ultraviolet) common to water treatment could be considered to reduce the loading of copollutants in the water wash section, although their efficacy is still in development and it is possible that partial treatment could result in the formation of additional degradation products. Apart from these potential controls, any increase in VOC emissions from a CCS retrofit project would be mitigated through NSR permitting. As such VOC increases are not expected to be large enough to trigger major NSR requirements, they would likely be reviewed and addressed under a state's minor NSR program.

There is one nitrosamine that is a listed HAP regulated under CAA section 112. Carbon capture systems that are themselves a major source of HAP should evaluate the applicability of CAA section 112(g) and conduct a case-by-case MACT analysis if required, to establish MACT for any listed HAP, including listed nitrosamines, formaldehyde, and acetaldehyde. Because of the differences in the formation and effectiveness of controls, such a case-by-case MACT analysis should evaluate the performance of controls for nitrosamines and aldehydes separately, as formaldehyde or acetaldehyde may not be a suitable surrogate for amine and nitrosamine emissions. However, measurement of nitrosamine emissions may be challenging when the concentration is low (*e.g.,* less than 1 part per billion, dry basis).

HAP emissions from the CO_2 capture plant will depend on the flue gas

[647] As of September 21, 2023, the Good Neighbor Plan ''Group 3'' ozone-season NO_X control program for power plants is being implemented in the following states: Illinois, Indiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and Wisconsin. Pursuant to court orders staying the Agency's FIP Disapproval action as to the following states, the EPA is not currently implementing the Good Neighbor Plan ''Group 3'' ozone-season NO_X control program for power plants in the following states: Alabama, Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and West Virginia.

[648] Sharma, S., Azzi, M., ''A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies,'' *Fuel,* 121, 178 (2014).

[649] Mertens, J., *et al.,* ''Understanding ethanolamine (MEA) and ammonia emissions from amine-based post combustion carbon capture: Lessons learned from field tests,'' *Int'l J. of GHG Control,* 13, 72 (2013).

[650] U.S. Department of Energy (DOE). Pathways to Commercial Liftoff: Carbon Management. *https://liftoff.energy.gov/wp-content/uploads/2023/04/20230424-Liftoff-Carbon-Management-vPUB_update.pdf.*

conditions, solvent, size of the source, and process design. The air permit application for Project Tundra [651] includes potential-to-emit (PTE) values for CAA section 112 listed HAP specific to the 530 MW-equivalent CO_2 capture plant, including emissions of 1.75 tons per year (TPY) of formaldehyde (CASRN 50–00–0), 32.9 TPY of acetaldehyde (CASRN 75–07–0), 0.54 TPY of acetamide (CASRN 60–35–5), 0.018 TPY of ethylenimine (CASRN 151–56–4), 0.044 TPY of N-nitrosodimethylamine (CASRN 62–75–9), and 0.018 TPY of N-nitrosomorpholine (CASRN 59–89–2). Additional PTE other species that are not CAA section 112 listed HAP were also included, including 0.022 TPY of N-nitrosodiethylamine (CASRN 55–18–5). PTE values for other CO_2 capture plants may differ. To comply with North Dakota Department of Environmental Quality (ND–DEQ) Air Toxics Policy, an air toxics assessment was included in the permit application. According to that assessment, the total maximum individual carcinogenic risk was 1.02E–6 (approximately 1-in-1 million, below the ND–DEQ threshold of 1E–5) primarily driven by N-nitrosodiethylamine and N-nitrosodimethylamine. The hazard index value was 0.022 (below the ND–DEQ threshold of 1), with formaldehyde being the primary driver. Results of air toxics risk assessments for other facilities would depend on the emissions from the facility, controls in place, stack height and flue gas conditions, local ambient conditions, and the relative location of the exposed population.

Emissions of amines and nitrosamines at Project Tundra are controlled by the water wash section of the absorber column. According to the permit to construct issued by ND–DEQ, limits for formaldehyde and acetaldehyde will be established based on testing after initial operation of the CO_2 capture plant. The permit does not include a mechanism for establishing limits for nitrosamine emissions, as they may be below the limit of detection (less than 1 part per billion, dry basis).

The EPA received several comments related to the potential for non-GHG emissions associated with CCS. Those comments and the EPA's responses are as follows.

Comment: Some commenters noted that there is a potential for increases in co-pollutants when operating amine-based CO_2 capture systems. One commenter requested that the EPA proactively regulate potential nitrosamine emissions.

Response: The EPA carefully considered these concerns as it finalized its determination of the BSERs for these rules. The EPA takes these concerns seriously, agrees that any impacts to local and downwind communities are important to consider and has done so as part of its analysis discussed at section XII.E. While the EPA acknowledges that, in some circumstances, there is potential for some non-GHG emissions to increase, there are several protections in place to help mitigate these impacts. The EPA believes that these protections, along with the meaningful engagement of potentially affected communities, can facilitate a responsible deployment of this technology that mitigates the risk of any adverse impacts.

There is one nitrosamine that is a listed HAP under CAA section 112 (N-Nitrosodimethylamine; CASRN 62–75–9). Other nitrosamines would have to be listed before the EPA could establish regulations limiting their emission. Furthermore, carbon capture systems are themselves not a listed source category of HAP, and the listing of a source category under CAA section 112 would first require some number of the sources to exist for the EPA to develop MACT standards. However, if a new CO_2 capture facility were to be permitted as a separate entity (rather than as part of the EGU) then it may be subject to case-by-case MACT under section 112(g), as detailed in the preceding section of this preamble.

Comment: Commenters noted that a source could attempt to permit CO_2 facilities as separate entities to avoid triggering NSR for the EGU.

Response: For the CO_2 capture plant to be permitted as a separate entity, the source would have to demonstrate to the state permitting authority that the EGU and CO_2 capture plant are not a single stationary source under the NSR program. In determining what constitutes a stationary source, the EPA's NSR regulations set forth criteria that are to be used when determining the scope of a ''stationary source.'' [652] These criteria require the aggregation of different pollutant-emitting activities if they (1) belong to the same industrial grouping as defined by SIC codes, (2) are located on contiguous or adjacent properties, and (3) are under common control.[653] In the case of an EGU and CO_2 capture plant that are collocated, to permit them as separate sources they should not be under common control or not be defined by the same industrial grouping.

The EPA would anticipate that, in most cases, the operation of the EGU and the CO_2 capture plant will intrinsically affect one another—typically steam, electricity, and the flue gas of the EGU will be provided to the CO_2 capture plant. Conditions of the flue gas will affect the operation of the CO_2 capture plant, including its emissions, and the steam and electrical load will affect the operation of the EGU. Moreover, the emissions from the EGU will be routed through the CO_2 capture system and emitted out of the top of the CO_2 absorber. Even if the EGU and CO_2 capture plant are owned by separate entities, the CO_2 capture plant is likely to be on or directly adjacent to land owned by the owners of the EGU and contractual obligations are likely to exist between the two owners. While each of these individual factors may not ultimately determine the outcome of whether two nominally-separate facilities should be treated as a single stationary source for permitting purposes, the EPA expects that in most cases an EGU and its collocated CO_2 capture plant would meet each of the aforementioned NSR regulatory criteria necessary to make such a determination. Thus, the EPA generally would not expect an EGU and its CO_2 capture plant to be permitted as separate stationary sources.

(C) Water Use

Water consumption at the plant increases when applying carbon capture, due to solvent water makeup and cooling demand. Water consumption can increase by 36 percent on a gross basis.[654] A separate cooling water system dedicated to a CO_2 capture plant may be necessary. However, the amount of water consumption depends on the design of the cooling system. For example, the cooling system cited in the CCS feasibility study for SaskPower's Shand Power station would rely entirely on water condensed from the flue gas and thus would not require any increase in external water consumption—all while achieving higher capture rates at lower cost than Boundary Dam Unit 3.[655] Regions with limited water supply

[651] DCC East PTC Application. *https://ceris.deq.nd.gov/ext/nsite/map/results/detail/-8992368000928857057/documents.*

[652] 40 CFR 51.165(a)(1)(i) and (ii); 40 CFR 51.166(b)(5) and (6).

[653] The EPA has issued guidance to clarify these regulatory criteria of stationary source determination. See *https://www.epa.gov/nsr/single-source-determination.*

[654] DOE/NETL–2016/1796. ''Eliminating the Derate of Carbon Capture Retrofits.'' May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9.*

[655] International CCS Knowledge Centre. The Shand CCS Feasibility Study Public Report. *https://*

Continued

may therefore rely on dry or hybrid cooling systems. Therefore, the EPA considers the water use requirements to be manageable and does not expect this consideration to preclude coal-fired power plants generally from being able to install and operate CCS.

(D) CO_2 Capture Plant Siting

With respect to siting considerations, CO_2 capture systems have a sizeable physical footprint and a consequent land-use requirement. One commenter cited their analysis showing that, for a subset of coal-fired sources greater than 300 MW, 98 percent (154 GW of the existing fleet) have adjacent land available within 1 mile of the facility, and 83 percent have adjacent land available within 100 meters of the facility. Furthermore, the cited analysis did not include land available onsite, and it is therefore possible there is even greater land availability for siting capture equipment. Qualitatively, some commenters claimed there is limited land available for siting CO_2 capture plants adjacent to coal-fired steam generating units. However, those commenters provided no data or analysis to support their assertion. The EPA has reviewed the analysis provided by the first commenter, and the approach, methods, and assumptions are logical. Further, the EPA has reviewed the available information, including the location of coal-fired steam generating units and visual inspection of the associated maps and plots. Although in some cases longer duct runs may be required, this would not preclude coal-fired power plants generally from being able to install and operate CCS. Therefore, the EPA has concluded that siting and land-use requirements for CO_2 capture are not unreasonable.

(E) Transport and Geologic Sequestration

As noted in section VII.C.1.a.i(C) of this preamble, PHMSA oversight of supercritical CO_2 pipeline safety protects against environmental release during transport. The vast majority of CO_2 pipelines have been operating safely for more than 60 years. PHMSA reported a total of 102 CO_2 pipeline incidents between 2003 and 2022, with one injury (requiring in-patient hospitalization) and zero fatalities.[656] In the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines with zero incidents involving fatalities.[657] PHMSA initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of supercritical CO_2 pipelines. Furthermore, UIC Class VI and Class II regulations under the SDWA, in tandem with GHGRP subpart RR and subpart VV requirements, ensure the protection of USDWs and the security of geologic sequestration. The EPA believes these protections constitute an effective framework for addressing potential health and environmental concerns related to CO_2 transportation and sequestration, and the EPA has taken this regulatory framework into consideration in determining that CCS represents the BSER for long-term steam EGUs.

(F) Impacts on the Energy Sector

Additionally, the EPA considered the impacts on the power sector, on a nationwide and long-term basis, of determining CCS to be the BSER for long-term coal-fired steam generating units. In this final action, the EPA considers that designating CCS as the BSER for these units would have limited and non-adverse impacts on the long-term structure of the power sector or on the reliability of the power sector. Absent the requirements defined in this action, the EPA projects that 11 GW of coal-fired steam generating units would apply CCS by 2035 and an additional 30 GW of coal-fired steam generating units, without controls, would remain in operation in 2040. Designating CCS to be the BSER for existing long-term coal-fired steam generating units may result in more of the coal-fired steam generating unit capacity applying CCS. The time available before the compliance deadline of January 1, 2032, provides for adequate resource planning, including accounting for the downtime necessary to install the CO_2 capture equipment at long-term coal-fired steam generating units. For the 12-year duration that eligible EGUs earn the IRC section 45Q tax credit, long-term coal-fired steam generating units are anticipated to run at or near base load conditions in order to maximize the amount of tax credit earned through IRC section 45Q. Total generation from coal-fired steam generating units in the medium-term subcategory would gradually decrease over an extended period of time through 2039, subject to the commitments those units have chosen to adopt. Additionally, for the long-term units applying CCS, the EPA has determined that the increase in the annualized cost of generation is reasonable. Therefore, the EPA concludes that these elements of BSER can be implemented while maintaining a reliable electric grid. A broader discussion of reliability impacts of these final rules is available in section XII.F of this preamble.

iv. Extent of Reductions in CO_2 Emissions

CCS is an extremely effective technology for reducing CO_2 emissions. As of 2021, coal-fired power plants are the largest stationary source of GHG emissions by sector. Furthermore, emission rates (lb CO_2/MWh-gross) from coal-fired sources are almost twice those of natural gas-fired combined cycle units, and sources operating in the long-term have the more substantial emissions potential. CCS can be applied to coal-fired steam generating units at the source to reduce the mass of CO_2 emissions by 90 percent or more. Increased steam and power demand have a small impact on the reduction in emission rate (*i.e.,* lb CO_2/MWh-gross) that occurs with 90 percent capture. According to the 2016 NETL Retrofit report, 90 percent capture will result in emission rates that are 88.4 percent lower on a lb/MWh-gross basis and 87.1 percent lower on a lb/MWh-net basis compared to units without capture.[658] After capture, CO_2 can be transported and securely sequestered.[659] Although steam generating units with CO_2 capture will have an incentive to operate at higher utilization because the cost to install the CCS system is largely fixed and the IRC section 45Q tax credit increases based on the amount of CO_2 captured and sequestered, any increase in utilization will be far outweighed by the substantial reductions in emission rate.

v. Promotion of the Development and Implementation of Technology

The EPA considered the potential impact on technology advancement of designating CCS as the BSER for long-term coal-fired steam generating units, and in this final rule, the EPA considers

ccsknowledge.com/pub/Publications/Shand_CCS_Feasibility_Study_Public_Report_Nov2018_(2021-05-12).pdf.

[656] NARUC. (2023). Onshore U.S. Carbon Pipeline Deployment: Siting, Safety. and Regulation. Prepared by Public Sector Consultants for the National Association of Regulatory Utility Commissioners (NARUC). June 2023. *https://pubs.naruc.org/pub/F1EECB6B-CD8A-6AD4-B05B-E7DA0F12672E.*

[657] Congressional Research Service. 2022. Carbon Dioxide Pipelines: Safety Issues, CRS Reports, June 3, 2022. *https://crsreports.congress.gov/product/pdf/IN/IN11944.*

[658] DOE/NETL–2016/1796. ''Eliminating the Derate of Carbon Capture Retrofits.'' May 31, 2016. *https://www.netl.doe.gov/energy-analysis/details?id=e818549c-a565-4cbc-94db-442a1c2a70a9.*

[659] Intergovernmental Panel on Climate Change. (2005). Special Report on Carbon Dioxide Capture and Storage.

that designating CCS as the BSER will provide for meaningful advancement of CCS technology. As indicated above, the EPA's IPM modeling indicates that 11 GW of coal-fired power plants install CCS and generate 76 terawatt-hours (TWh) per year in the base case, and that another 8 GW of plants install CCS and generate another 57 TWh per year in the policy case. In this manner, this rule advances CCS technology more widely throughout the coal-fired power sector. As discussed in section VIII.F.4.c.iv(G) of this preamble, this rule advances CCS technology for new combined cycle base load combustion turbines, as well. It is also likely that this rule supports advances in the technology in other industries.

vi. Comparison With 2015 NSPS For Newly Constructed Coal-Fired EGUs

In the 2015 NSPS, the EPA determined that the BSER for newly constructed coal-fired EGUs was based on CCS with 16 to 23 percent capture, based on the type of coal combusted, and consequently, the EPA promulgated standards of performance of 1,400 lb CO_2/MWh-g. 80 FR 64512 (table 1), 64513 (October 23, 2015). The EPA made those determinations based on the costs of CCS at the time of that rulemaking. In general, those costs were significantly higher than at present, due to recent technology cost declines as well as related policies, including the IRC section 45Q tax credit for CCS, which were not available at that time for purposes of consideration during the development of the NSPS. *Id.* at 64562 (table 8). Based on of these higher costs, the EPA determined that 16–23 percent capture qualified as the BSER, rather than a significantly higher percentage of capture. Given the substantial differences in the cost of CCS during the time of the 2015 NSPS and the present time, the capture percentage of the 2015 NSPS necessarily differed from the capture percentage in this final action, and, by the same token, the associated degree of emission limitation and resulting standards of performance necessarily differ as well. If the EPA had strong evidence to indicate that new coal-fired EGUs would be built, it would propose to revise the 2015 NSPS to align the BSER and emissions standards to reflect the new information regarding the costs of CCS. Because there is no evidence to suggest that there are any firm plans to build new coal-fired EGUs in the future, however, it is not at present a good use of the EPA's limited resources to propose to update the new source standard to align with the existing source standard finalized today. While the EPA is not revising the new source standard for new coal-fired EGUs in this action, the EPA is retaining the ability to propose review in the future.

vii. Requirement That Source Must Transfer CO_2 to an Entity That Reports Under the Greenhouse Gas Reporting Program

The final rule requires that EGUs that capture CO_2 in order to meet the applicable emission standard report in accordance with the GHGRP requirements of 40 CFR part 98, including subpart PP. GHGRP subpart RR and subpart VV requirements provide the monitoring and reporting mechanisms to quantify CO_2 storage and to identify, quantify, and address potential leakage. Under existing GHGRP regulations, sequestration wells permitted as Class VI under the UIC program are required to report under subpart RR. Facilities with UIC Class II wells that inject CO_2 to enhance the recovery of oil or natural gas can opt-in to reporting under subpart RR by submitting and receiving approval for a monitoring, reporting, and verification (MRV) plan. Subpart VV applies to facilities that conduct enhanced recovery using ISO 27916 to quantify geologic storage unless they have opted to report under subpart RR. For this rule, if injection occurs on site, the EGU must report data accordingly under 40 CFR part 98 subpart RR or subpart VV. If the CO_2 is injected off site, the EGU must transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR or subpart VV. They may also transfer the captured CO_2 to a facility that has received an innovative technology waiver from the EPA.

b. Options Not Determined To Be the BSER for Long-Term Coal-Fired Steam Generating Units

In this section, we explain why CCS at 90 percent capture best balances the BSER factors and therefore why the EPA has determined it to be the best of the possible options for the BSER.

i. Partial Capture CCS

Partial capture for CCS was not determined to be BSER because the emission reductions are lower and the costs would, in general, be higher. As discussed in section IV.B of this preamble, individual coal-fired power plants are by far the highest-emitting plants in the nation, and the coal-fired power plant sector is higher-emitting than any other stationary source sector. CCS at 90 percent capture removes very high absolute amounts of emissions. Partial capture CCS would fail to capture large quantities of emissions. With respect to costs, designs for 90 percent capture in general take greater advantage of economies of scale. Eligibility for the IRC section 45Q tax credit for existing EGUs requires design capture rates equivalent to 75 percent of a baseline emission rate by mass. Even assuming partial capture rates meet that definition, lower capture rates would receive fewer returns from the IRC section 45Q tax credit (since these are tied to the amount of carbon sequestered, and all else being equal lower capture rates would result in lower amounts of sequestered carbon) and costs would thereby be higher.

ii. Natural Gas Co-Firing

(A) Reasons Why Not Selected as BSER

As discussed in section VII.C.2, the EPA is determining 40 percent natural gas co-firing to qualify as the BSER for the medium-term subcategory of coal-fired steam generating units. This subcategory consists of units that will permanently cease operation by January 1, 2039. In making this BSER determination, the EPA analyzed the ability of all existing coal-fired units—not only medium-term units—to install and operate 40 percent co-firing. As a result, all of the determinations concerning the criteria for BSER that the EPA made for 40 percent co-firing apply to all existing coal-fired units, including the units in the long-term subcategory. For example, 40 percent co-firing is adequately demonstrated for the long-term subcategory, and has reasonable energy requirements and reasonable non-air quality environmental impacts. It would also be of reasonable cost for the long-term subcategory. Although the capital expenditure for natural gas co-firing is lower than CCS, the variable costs are higher. As a result, the total costs of natural gas co-firing, in general, are higher on a $/ton basis and not substantially lower on a $/MWh basis, than for CCS. Were co-firing the BSER for long-term units, the cost that industry would bear might then be considered similar to the cost for CCS. In addition, the GHG Mitigation Measures TSD shows that all coal-fired units would be able to achieve the requisite infrastructure build-out and obtain sufficient quantities of natural gas to comply with standards of performance based on 40 percent co-firing by January 1, 2030.

The EPA is not selecting 40 percent natural gas co-firing as the BSER for the long-term subcategory, however, because it requires substantially less emission reductions at the unit-level than 90 percent capture CCS. Natural gas co-firing at 40 percent of the heat

input to the steam generating unit achieves 16 percent reductions in emission rate at the stack, while CCS achieves an 88.4 percent reduction in emission rate. As discussed in section IV.B of this preamble, individual coal-fired power plants are by far the highest-emitting plants in the nation, and the coal-fired power plant sector is higher-emitting than any other stationary source sector. Because the unit-level emission reductions achievable by CCS are substantially greater, and because CCS is of reasonable cost and matches up well against the other BSER criteria, the EPA did not determine natural gas co-firing to be BSER for the long-term subcategory although, under other circumstances, it could be. Determining BSER requires the EPA to select the ''best'' of the systems of emission reduction that are adequately demonstrated, as described in section V.C.2; in this case, there are two systems of emission reduction that match up well against the BSER criteria, but based on weighing the criteria together, and in light of the substantially greater unit-level emission reductions from CCS, the EPA has determined that CCS is a better system of emission reduction than co-firing for the long-term subcategory.

The EPA notes that if a state demonstrates that a long-term coal-fired steam generating unit cannot install and operate CCS and cannot otherwise reasonably achieve the degree of emission limitation that the EPA has determined based on CCS, following the process the EPA has specified in its applicable regulations for consideration of RULOF, the state would evaluate natural gas co-firing as a potential basis for establishing a less stringent standard of performance, as detailed in section X.C.2 of this document.

iii. Heat Rate Improvements

Heat rate improvements were not considered to be BSER for long-term steam generating units because the achievable reductions are very low and may result in a rebound effect whereby total emissions from the source increase, as detailed in section VII.D.4.a of this preamble.

Comment: One commenter requested that HRI be considered as BSER in addition to CCS, so that long-term sources would be required to achieve reductions in emission rate consistent with performing HRI and adding CCS with 90 percent capture to the source.

Response: As described in section VII.D.4.a, the reductions from HRI are very low and many sources have already made HRI, so that additional reductions are not available. It is possible that a source installing CO_2 capture will make efficiency improvements as a matter of best practices. For example, Boundary Dam Unit 3 made upgrades to the existing steam generating unit when CCS was installed, including installing a new steam turbine.[660] However, the reductions from efficiency improvements would not be additive to the reductions from CCS because of the impact of the CO_2 capture plant on the efficiency of source due to the required steam and electricity load of the capture plant.

c. Conclusion

Coal-fired EGUs remain the largest stationary source of dangerous CO_2 emissions. The EPA is finalizing CCS at a capture rate of 90 percent as the BSER for long-term coal-fired steam generating units because this system satisfies the criteria for BSER as summarized here. CCS at a capture rate of 90 percent as the BSER for long-term coal-fired steam generating units is adequately demonstrated, as indicated by the facts that it has been operated at scale, is widely applicable to these sources, and that there are vast sequestration opportunities across the continental U.S. Additionally, accounting for recent technology cost declines as well as policies including the tax credit under IRC section 45Q, the costs for CCS are reasonable. Moreover, any adverse non-air quality health and environmental impacts and energy requirements of CCS, including impacts on the power sector on a nationwide basis, are limited and can be effectively avoided or mitigated. In contrast, co-firing 40 percent natural gas would achieve far fewer emission reductions without improving the cost reasonableness of the control strategy.

These considerations provide the basis for finalizing CCS as the best of the systems of emission reduction for long-term coal-fired power plants. In addition, determining CCS as the BSER promotes advancements in control technology for CO_2, which is a relevant consideration when establishing BSER under section 111 of the CAA.

i. Adequately Demonstrated

CCS with 90 percent capture is adequately demonstrated based on the information in section VII.C.1.a.i of this preamble. Solvent-based CO_2 capture was patented nearly 100 years ago in the 1930s [661] and has been used in a variety of industrial applications for decades. Thousands of miles of CO_2 pipelines have been constructed and securely operated in the U.S. for decades.[662] And tens of millions of tons of CO_2 have been permanently stored deep underground either for geologic sequestration or in association with EOR.[663] There are currently at least 15 operating CCS projects in the U.S., and another 121 that are under construction or in advanced stages of development.[664] This broad application of CCS demonstrates the successful operation of all three components of CCS, operating both independently and simultaneously. Various CO_2 capture methods are used in industrial applications and are tailored to the flue gas conditions of a particular industry (see the final TSD, *GHG Mitigation Measures for Steam Generating Units* for details). Of those capture technologies, amine solvent-based capture has been demonstrated for removal of CO_2 from the post-combustion flue gas of fossil fuel-fired EGUs.

Since 1978, an amine-based system has been used to capture approximately 270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW Argus Cogeneration Plant (Trona, California).[665] Amine solvent capture has been further demonstrated at coal-fired power plants including AES's Warrior Run and Shady Point. And since 2014, CCS has been applied at the commercial scale at Boundary Dam Unit 3, a 110 MW lignite coal-fired steam generating unit in Saskatchewan, Canada.

Impending increases in Canadian regulatory CO_2 emission requirements have prompted optimization of Boundary Dam Unit 3 so that the facility now captures 83 percent of its total CO_2 emissions. Moreover, from the flue gas

[660] IEAGHG Report 2015–06. Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station. August 2015. *https://ieaghg.org/publications/technical-reports/reports-list/9-technical-reports/935-2015-06-integrated-ccs-project-at-saskpower-s-boundary-dam-power-station.*

[661] Bottoms, R.R. Process for Separating Acidic Gases (1930) United States patent application. United States Patent US1783901A; Allen, A.S. and Arthur, M. Method of Separating Carbon Dioxide from a Gas Mixture (1933) United States Patent Application. United States Patent US1934472A.

[662] U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration, ''Hazardous Annual Liquid Data.'' 2022. *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

[663] US EPA. GHGRP. *https://www.epa.gov/ghgreporting/supply-underground-injection-and-geologic-sequestration-carbon-dioxide.*

[664] Carbon Capture and Storage in the United States. CBO. December 13, 2023. *https://www.cbo.gov/publication/59345.*

[665] Dooley, J.J., *et al.* (2009). ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009.'' U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

treated, Boundary Dam Unit 3 consistently captured 90 percent or more of the CO_2 over a 3-year period. The adequate demonstration of CCS is further corroborated by the EPAct05-assisted 240MW-equivalent Petra Nova CCS project at the coal-fired W.A. Parish Unit 8, which achieved over 90 percent capture from the treated flue gas during a 3-year period. Additionally, the technical improvements put in practice at Boundary Dam Unit 3 and Petra Nova can be put in place on new capture facilities during initial construction. This includes redundancies and isolations for key equipment, and spray systems to limit fly ash carryover. Projects that have announced plans to install CO_2 capture directly include these improvements in their design and employ new solvents achieving higher capture rates that are commercially available from technology providers. As a result, these projects target capture efficiencies of at least 95 percent, well above the BSER finalized here.

Precedent, building upon the statutory text and context, has established that the EPA may make a finding of adequate demonstration by drawing upon existing data from individual commercial-scale sources, including testing at these sources,[666] and that the agency may make projections based on existing data to establish a more stringent standard than has been regularly shown,[667] in particular in cases when the agency can specifically identify technological improvements that can be expected to achieve the standard in question.[668] Further, the EPA may extrapolate based on testing at a particular kind of source to conclude that the technology at issue will also be effective at a different, related, source.[669] Following this legal standard, the available data regarding performance and testing at Boundary Dam, a commercial-scale plant, is enough, by itself, to support the EPA's adequate demonstration finding for a 90 percent standard. In addition to this, however, in the 9 years since Boundary Dam began operating, operators and the EPA have developed a clear understanding of specific technological improvements which, if implemented, the EPA can reasonably expect to lead to a 90 percent capture rate on a regular and ongoing basis. The D.C. Circuit has established that this information is more than enough to establish that a 90 percent standard is achievable.[670] And per *Lignite Energy Council,* the findings from Boundary Dam can be extrapolated to other, similarly operating power plants, including natural gas plants.[671]

Transport of CO_2 and geological storage of CO_2 have also been adequately demonstrated, as detailed in VII.C.1.a.i(B)(7) and VII.C.1.a.i(D)(2). CO_2 has been transported through pipelines for over 60 years, and in the past 20 years, 500 million metric tons of CO_2 moved through over 5,000 miles of CO_2 pipelines. CO_2 pipeline controls and PHMSA standards ensure that captured CO_2 will be securely conveyed to a sequestration site. Due to the proximity of sources to storage, it would be feasible for most sources to build smaller and shorter source-to-sink laterals, rather than rely on a trunkline network buildout. In addition to pipelines, CO_2 can also be transported via vessel, highway, or rail. Geological storage is proven and broadly available, and of the coal-fired steam generating units with planned operation during or after 2030, 77 percent are within 40 miles of the boundary of a saline reservoir.

The EPA also considered the timelines, materials, and workforce necessary for installing CCS, and determined they are sufficient.

ii. Cost

Process improvements have resulted in a decrease in the projected costs to install CCS on existing coal-fired steam generating units. Additionally, the IRC section 45Q tax credit provides $85 per metric ton ($77 per ton) of CO_2. It is reasonable to account for the IRC section 45Q tax credit because the costs that should be accounted for are the costs to the source. For the fleet of coal-fired steam generating units with planned operation during or after 2033, and assuming a 12-year amortization period and 80 percent annual capacity factor and including source specific transport and storage costs, the average total costs of CCS are −$5/ton of CO_2 reduced and −$4/MWh. And even for shorter amortization periods, the $/MWh costs are comparable to or less than the costs for other controls ($10.60–$18.50/MWh) for a substantial number of sources. Notably, the EPA's IPM model projects that even without this final rule—that is, in the base case, without any CAA section 111 requirements—some units would deploy CCS. Similarly, the IPM model projects that even if this rule determined 40 percent co-firing to be the BSER for long-term coal, instead of CCS, some additional units would deploy CCS. Therefore, the costs of CCS with 90 percent capture are reasonable.

iii. Non-Air Quality Health and Environmental Impacts and Energy Requirements

The CO_2 capture plant requires substantial pre-treatment of the flue gas to remove SO_2 and fly ash (PM) while other controls and process designs are necessary to minimize solvent degradation and solvent loss. Although CCS has the potential to result in some increases in non-GHG emissions, a robust regulatory framework, generally implemented at the state level, is in place to mitigate other non-GHG emissions from the CO_2 capture plant. For transport, pipeline safety is regulated by PHMSA, while UIC Class VI regulations under the SDWA, in tandem with GHGRP subpart RR requirements, ensure the protection of USDWs and the security of geologic sequestration. Therefore, the potential non-air quality health and environmental impacts do not militate against designating CCS as the BSER for long-term steam EGUs. The EPA also considered energy requirements. While the CO_2 capture plant requires steam and electricity to operate, the incentives provided by the IRC section 45Q tax credit will likely result in increased total generation from the source. Therefore, the energy requirements are not unreasonable, and there would be limited, non-adverse impacts on the broader energy sector.

2. Medium-Term Coal-Fired Steam Generating Units

The EPA is finalizing its conclusion that 40 percent natural gas co-firing on a heat input basis is the BSER for medium-term coal-fired steam generating units. Co-firing 40 percent natural gas, on an annual average heat input basis, results in a 16 percent reduction in CO_2 emission rate. The technology has been adequately demonstrated, can be implemented at reasonable cost, does not have significant adverse non-air quality health and environmental impacts or energy requirements, including impacts on the energy sector, and achieves meaningful reductions in CO_2 emissions. Co-firing also advances useful control technology, which provides additional, although not essential, support for treating it as the BSER.

[666] *See Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775 (D.C. Cir. 1976).

[667] *See id.*

[668] *See Sierra Club* v. *Costle,* 657 F.2d 298 (1981).

[669] *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[670] *See, e.g., Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (1981).

[671] 198 F.3d 930 (D.C. Cir. 1999).

a. Rationale for the Medium-Term Coal-Fired Steam Generating Unit Subcategory

For the development of the emission guidelines, the EPA first considered CCS as the BSER for existing coal-fired steam generating units. CCS generally achieves significant emission reductions at reasonable cost. Typically, in setting the BSER, the EPA assumes that regulated units will continue to operate indefinitely. However, that assumption is not appropriate for all coal-fired steam generating units. 62 percent of existing coal-fired steam generating units greater than 25 MW have already announced that they will retire or convert from coal to gas by 2039.[672] CCS is capital cost-intensive, entailing a certain period to amortize the capital costs. Therefore, the EPA evaluated the costs of CCS for different amortization periods, as detailed in section VII.C.1.a.ii of the preamble, and determined that CCS was cost reasonable, on average, for sources operating more than 7 years after the compliance date of January 1, 2032. Accordingly, units that cease operating before January 1, 2039, will generally have less time to amortize the capital costs, and the costs for those sources would be higher and thereby less comparable to those the EPA has previously determined to be reasonable. Considering this, and the other factors evaluated in determining BSER, the EPA is not finalizing CCS as BSER for units demonstrating that they plan to permanently cease operation prior to January 1, 2039.

Instead, the EPA is subcategorizing these units into the medium-term subcategory and finalizing a BSER based on 40 percent natural gas co-firing on a heat input basis for these units. Co-firing natural gas at 40 percent has significantly lower capital costs than CCS and can be implemented by January 1, 2030. For sources that expect to continue in operation until January 1, 2039, and that therefore have a 9-year amortization period, the costs of 40 percent co-firing are $73/ton of CO_2 reduced or $13/MWh of generation, which supports their reasonableness because they are comparable to or less than the costs detailed in section VII.C.1.a.ii(D) of this preamble for other controls on EGUs ($10.60 to $18.50/MWh) and for GHGs for the Crude Oil and Natural Gas source category in the 2016 NSPS of $98/ton of CO_{2e} reduced (80 FR 56627; September 18, 2015). Co-firing is also cost-reasonable for sources permanently ceasing operations sooner, and that therefore have a shorter amortization period. As discussed in section VII.B.2 of this preamble, with a two-year amortization period, many units can co-fire with meaningful amounts of natural gas at reasonable cost. Of course, even more can co-fire at reasonable costs with amortization periods longer than two years. For example, the EPA has determined that 33 percent of sources with an amortization period of at least three years have costs for 40 percent co-firing below both of the $/ton and $/MWh metrics, and 68 percent of those sources have costs for 20 percent co-firing below both of those metrics. Therefore, recognizing that operating horizon affects the cost reasonableness of controls, the EPA is finalizing a separate subcategory for coal-fired steam generating units operating in the medium-term—those demonstrating that they plan to permanently cease operation after December 31, 2031, and before January 1, 2039—with 40 percent natural gas co-firing as the BSER.

i. Legal Basis for Establishing the Medium-Term Subcategory

As noted in section V.C.1 of this preamble, the EPA has broad authority under CAA section 111(d) to identify subcategories. As also noted in section V.C.1, the EPA's authority to ''distinguish among classes, types, and sizes within categories,'' as provided under CAA section 111(b)(2) and as we interpret CAA section 111(d) to provide as well, generally allows the Agency to place types of sources into subcategories when they have characteristics that are relevant to the controls that the EPA may determine to be the BSER for those sources. One element of the BSER is cost reasonableness. See CAA section 111(d)(1) (requiring the EPA, in setting the BSER, to ''tak[e] into account the cost of achieving such reduction''). As noted in section V, the EPA's longstanding regulations under CAA section 111(d) explicitly recognize that subcategorizing may be appropriate for sources based on the ''costs of control.'' [673] Subcategorizing on the basis of operating horizon is consistent with a key characteristic of the coal-fired power industry that is relevant for determining the cost reasonableness of control requirements: A large percentage of the sources in the industry have already announced, and more are expected to announce, dates for ceasing operation, and the fact that many coal-fired steam generating units intend to cease operation in the near term affects what controls are ''best'' for different subcategories.[674] At the outset, installation of emission control technology takes time, sometimes several years. Whether the costs of control are reasonable depends in part on the period of time over which the affected sources can amortize those costs. Sources that have shorter operating horizons will have less time to amortize capital costs. Thus, the annualized cost of controls may thereby be less comparable to the costs the EPA has previously determined to be reasonable.[675]

In addition, subcategorizing by length of period of continued operation is similar to two other bases for subcategorization on which the EPA has relied in prior rules, each of which implicates the cost reasonableness of controls: The first is load level, noted in section V.C.1. of this preamble. For

[672] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[673] 40 CFR 60.22(b)(5), 60.22a(b)(5).

[674] The EPA recognizes that section 111(d) provides that in applying standards of performance, a state may take into account, among other factors, the remaining useful life of a facility. The EPA believes that provision is intended to address exceptional circumstances at particular facilities, while the EPA has the responsibility to determine how to address the source category as a whole. See 88 FR 80480, 80511 (November 17, 2023) (''Under CAA 111, EPA must provide BSER and degree of emission limitation determinations that are, to the extent reasonably practicable, applicable to all designated facilities in the source category. In many cases, this requires the EPA to create subcategories of designated facilities, each of which has a BSER and degree of emission limitation tailored to its circumstances. . . . However, as Congress recognized, this may not be possible in every instance because, for example, it is not be feasible [sic] for the Agency to know and consider the idiosyncrasies of every designated facility or because the circumstances of individual facilities change after the EPA determined the BSER.'') (internal citations omitted). That a state may take into account the remaining useful life of an individual source, however, does not bar the EPA from considering operating horizon as a factor in determining whether subcategorization is appropriate. As discussed, the authority to subcategorize is encompassed within the EPA's authority to identify the BSER. Here, where many units share similar characteristics and have announced intended shorter operating horizons, it is permissible for the EPA to take operating horizon into account in determining the BSER for this subcategory of sources. States may continue to take RULOF factors into account for particular units where the information relevant to those units is fundamentally different than the information the EPA took into account in determining the degree of emission limitation achievable through application of the BSER. Should a court conclude that the EPA does not have the authority to create a subcategory based on the date at which units intend to cease operation, then the EPA believes it would be reasonable for states to consider co-firing as an alternative to CCS as an option for these units through the states' authority to consider, among other factors, remaining useful life.

[675] Steam Electric Reconsideration Rule, 85 FR 64650, 64679 (October 13, 2020) (distinguishes between EGUs retiring before 2028 and EGUs remaining in operation after that time).

example, in the 2015 NSPS, the EPA divided new natural gas-fired combustion turbines into the subcategories of base load and non-base load. 80 FR 64602 (table 15) (October 23, 2015). The EPA did so because the control technologies that were ''best''—including consideration of feasibility and cost reasonableness—depended on how much the unit operated. The load level, which relates to the amount of product produced on a yearly or other basis, bears similarity to a limit on a period of continued operation, which concerns the amount of time remaining to produce the product. In both cases, certain technologies may not be cost-reasonable because of the capacity to produce product—*i.e.,* the costs are spread over less product produced. Subcategorization on this basis is also supported by how utilities manage their assets over the long term, and was widely supported by industry commenters.

The second basis for subcategorization on which EPA has previously relied is fuel type, as also noted in section V.C.1 of this preamble. The 2015 NSPS provides an example of this type of subcategorization as well. There, the EPA divided new combustion turbines into subcategories on the basis of type of fuel combusted. *Id.* Subcategorizing on the basis of the type of fuel combusted may be appropriate when different controls have different costs, depending on the type of fuel, so that the cost reasonableness of the control depends on the type of fuel. In that way, it is similar to subcategorizing by operating horizon because in both cases, the subcategory is based upon the cost reasonableness of controls. Subcategorizing by operating horizon is also tantamount to the length of time over which the source will continue to combust the fuel. Subcategorizing on this basis may be appropriate when different controls for a particular fuel have different costs, depending on the length of time when the fuel will continue to be combusted, so that the cost reasonableness of controls depends on that timeframe. Some prior EPA rules for coal-fired sources have made explicit the link between length of time for continued operation and type of fuel combusted by codifying federally enforceable retirement dates as the dates by which the source must ''cease burning coal.'' [676]

As noted above, creating a subcategory on the basis of operating horizon does not preclude a state from considering RULOF in applying a standard of performance to a particular source. The EPA's authority to set BSER for a source category (including subcategories) and a state's authority to invoke RULOF for individual sources within a category or subcategory are distinct. The EPA's statutory obligation is to determine a generally applicable BSER for a source category, and where that source category encompasses different classes, types, or sizes of sources, to set generally applicable BSERs for subcategories accounting for those differences. By contrast, states' authority to invoke RULOF is premised on the state's ability to take into account information relevant to individual units that is fundamentally different than the information the EPA took into account in determining BSER generally. As noted, the EPA may subcategorize on the basis of cost of controls, and operating horizon may factor into the cost of controls. Moreover, through section 111(d)(1), Congress also required the EPA to develop regulations that permit states to consider ''among other factors, the remaining useful life'' of a particular existing source. The EPA has interpreted these other factors to include costs or technical feasibility specific to a particular source, even though these are factors the EPA itself considers in setting the BSER. In other words, the factors the EPA may consider in setting the BSER and the factors the states may consider in applying standards of performance are not distinct. As noted above, the EPA is finalizing these subcategories in response to requests by power sector representatives that this rule accommodate the fact that there is a class of sources that plan to voluntarily cease operations in the near term. Although the EPA has designed the subcategories to accommodate those requests, a particular source may still present source-specific considerations—whether related to its remaining useful life or other factors—that the state may consider relevant for the application of that particular source's standard of performance, and that the state should address as described in section X.C.2 of this preamble.

ii. Comments Received on Existing Coal-Fired Subcategories

Comment: The EPA received several comments on the proposed subcategories for coal-fired steam generating units. Many commenters, including industry commenters, supported these subcategories. Some commenters opposed these proposed subcategories. They argued that the subcategories were designed to force coal-fired power plants to retire.

Response: We disagree with comments suggesting that the subcategories for existing coal-fired steam EGUs that the EPA has finalized in this rule were designed to force retirements. The subcategories were not designed for that purpose, and the commenters do not explain their allegations to the contrary. The subcategories were designed, at industry's request,[677] to ensure that subcategories of units that can feasibly and cost-reasonably employ emissions reduction technologies—and only those subcategories of units that can do so—are required to reduce their emissions commensurate with those technologies. As explained above, in determining the BSER, the EPA generally assumes that a source will operate indefinitely, and calculates expected control costs on that basis. Under that assumption, the BSER for existing fossil-fuel fired EGUs is CCS. Nevertheless, the EPA recognizes that many fossil-fuel fired EGUs have already announced plans to cease operation. In recognition of this unique, distinguishing factor, the EPA determined whether a different BSER would be appropriate for fossil fuel-fired EGUs that do not intend to operate over the long term, and concluded, for the reasons stated above, that natural gas co-firing was appropriate for these sources that intended to cease operation before 2039. This subcategory is not intended to force retirements, and the EPA is not directing any state or any unit as to the choice of when to cease operation. Rather, the EPA has created this subcategory to accommodate these sources' intended operation plans. In fact, a number of industry commenters specifically requested and supported subcategories based on retirement dates in recognition of the reality that many operators are choosing to retire these units and that whether or not a control technology is feasible and cost-reasonable depends upon how long a unit intends to operate.

Specifically, as noted in section VII.B of this preamble, in this final action, the

[676] See 79 FR 5031, 5192 (January 30, 2014) (explaining that ''[t]he construction permit issued by Wyoming requires Naughton Unit 3 to *cease burning coal* by December 31, 2017, and to be retrofitted to natural gas as its fuel source by June 30, 2018'' (emphasis added)).

[677] As described in the proposal, during the early engagement process, industry stakeholders requested that the EPA ''[p]rovide approaches that allow for the retirement of units as opposed to investments in new control technologies, which could prolong the lives of higher-emitting EGUs; this will achieve maximum and durable environmental benefits.'' Industry stakeholders also suggested that the EPA recognize that some units may remain operational for a several-year period but will do so at limited capacity (in part to assure reliability), and then voluntarily cease operations entirely. 88 FR 33245 (May 23, 2023).

medium-term subcategory includes a date for permanently ceasing operation, which applies to coal-fired plants demonstrating that they plan to permanently cease operating after December 31, 2031, and before January 1, 2039. The EPA is retaining this subcategory because 55 percent of existing coal-fired steam generating units greater than 25 MW have already announced that they will retire or convert from coal to gas by January 1, 2039.[678] Accordingly, the costs of CCS—the high capital costs of which require a lengthy amortization period from its January 1, 2032, implementation date—are higher than the traditional metric for cost reasonableness for these sources. As discussed in section VII.C.2 of this preamble, the BSER for these sources is co-firing 40 percent natural gas. This is because co-firing, which has an implementation date of January 1, 2030, has lower capital costs and is therefore cost-reasonable for sources continuing to operate on or after January 1, 2032. It is further noted that this subcategory is elective. Furthermore, states also have the authority to establish a less stringent standard through RULOF in the state plan process, as detailed in section X.C.2 of this preamble.

In sum, these emission guidelines do not require any coal-fired steam EGU to retire, nor are they intended to induce retirements. Rather, these emission guidelines simply set forth presumptive standards that are cost-reasonable and achievable for each subcategory of existing coal-fired steam EGUs. See section VII.E.1 of this preamble (responding to comments that this rule violates the major questions doctrine).

Comment: The EPA broadly solicited comment on the dates and values defining the proposed subcategories for coal-fired steam generating units. Regarding the proposed dates for the subcategories, one industry stakeholder commented that the ''EPA's proposed retirement dates for applicability of the various subcategories are appropriate and broadly consistent with system reliability needs.'' [679] More specifically, industry commenters requested that the cease-operation-by date for the imminent-term subcategory be changed from January 1, 2032, to January 1, 2033. Industry commenters also stated that the 20 percent utilization limit in the definition of the near-term subcategory was overly restrictive and inconsistent with the emissions stringency of either the proposed medium term or imminent term subcategory—commenters requested greater flexibility for the near-term subcategory. Other comments from NGOs and other groups suggested various other changes to the subcategory definitions. One commenter requested moving the cease-operation-by date for the medium-term subcategory up to January 1, 2038, while eliminating the imminent-term subcategory and extending the near-term subcategory to January 1, 2038.

Response: The EPA is not finalizing the proposed imminent-term or near-term subcategories. The EPA is finalizing an applicability exemption for sources demonstrating that they plan to permanently cease operation prior to January 1, 2032, as detailed in section VII.B of this preamble. The EPA is finalizing the cease operating by date of January 1, 2039, for medium-term coal-fired steam generating units. These dates are all based on costs of co-firing and CCS, driven by their amortization periods, as discussed in the preceding sections of this preamble.

b. Rationale for Natural Gas Co-Firing as the BSER for Medium-Term Coal-Fired Steam Generating Units

In this section of the preamble, the EPA describes its rationale for natural gas co-firing as the final BSER for medium-term coal-fired steam generating units.

For a coal-fired steam generating unit, the substitution of natural gas for some of the coal, so that the unit fires a combination of coal and natural gas, is known as ''natural gas co-firing.'' The EPA is finalizing natural gas co-firing at a level of 40 percent of annual heat input as BSER for medium-term coal-fired steam generating units.

i. Adequately Demonstrated

The EPA is finalizing its determination that natural gas co-firing at the level of 40 percent of annual heat input is adequately demonstrated for coal-fired steam generating units. Many existing coal-fired steam generating units already use some amount of natural gas, and several have co-fired at relatively high levels at or above 40 percent of heat input in recent years.

(A) Boiler Modifications

Existing coal-fired steam generating units can be modified to co-fire natural gas in any desired proportion with coal, up to 100 percent natural gas. Generally, the modification of existing boilers to enable or increase natural gas firing typically involves the installation of new gas burners and related boiler modifications, including, for example, new fuel supply lines and modifications to existing air ducts. The introduction of natural gas as a fuel can reduce boiler efficiency slightly, due in large part to the relatively high hydrogen content of natural gas. However, since the reduction in coal can result in reduced auxiliary power demand, the overall impact on net heat rate can range from a 2 percent increase to a 2 percent decrease.

It is common practice for steam generating units to have the capability to burn multiple fuels onsite, and of the 565 coal-fired steam generating units operating at the end of 2021, 249 of them reported consuming natural gas as a fuel or startup source. Coal-fired steam generating units often use natural gas or oil as a startup fuel, to warm the units up before running them at full capacity with coal. While startup fuels are generally used at low levels (up to roughly 1 percent of capacity on an annual average basis), some coal-fired steam generating units have co-fired natural gas at considerably higher shares. Based on hourly reported CO_2 emission rates from the start of 2015 through the end of 2020, 29 coal-fired steam generating units co-fired with natural gas at rates at or above 60 percent of capacity on an hourly basis.[680] The capability of those units on an hourly basis is indicative of the extent of boiler burner modifications and sizing and capacity of natural gas pipelines to those units, and implies that those units are technically capable of co-firing at least 60 percent natural gas on a heat input basis on average over the course of an extended period (*e.g.,* a year). Additionally, during that same 2015 through 2020 period, 29 coal-fired steam generating units co-fired natural gas at over 40 percent on an annual heat input basis. Because of the number of units that have demonstrated co-firing above 40 percent of heat input, the EPA is finalizing that co-firing at 40 percent is adequately demonstrated. A more detailed discussion of the record of natural gas co-firing, including current trends, at coal-fired steam generating units is included in the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

(B) Natural Gas Pipeline Development

In addition to any potential boiler modifications, the supply of natural gas is necessary to enable co-firing at existing coal-fired steam boilers. As

[678] U.S. Environmental Protection Agency. National Electric Energy Data System (NEEDS) v7. December 2023. *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.*

[679] See Document ID No. EPA–HQ–OAR–2023–0072–0772.

[680] U.S. Environmental Protection Agency (EPA). ''Power Sector Emissions Data.'' Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data website: *https://campd.epa.gov.*

discussed in the previous section, many plants already have at least some access to natural gas. In order to increase natural gas access beyond current levels, plants may find it necessary to construct natural gas supply pipelines.

The U.S. natural gas pipeline network consists of approximately 3 million miles of pipelines that connect natural gas production with consumers of natural gas. To increase natural gas consumption at a coal-fired boiler without sufficient existing natural gas access, it is necessary to connect the facility to the natural gas pipeline transmission network via the construction of a lateral pipeline. The cost of doing so is a function of the total necessary pipeline capacity (which is characterized by the length, size, and number of laterals) and the location of the plant relative to the existing pipeline transmission network. The EPA estimated the costs associated with developing new lateral pipeline capacity sufficient to meet 60 percent of the net summer capacity at each coal-fired steam generating unit that could be included in this subcategory. As discussed in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* the EPA estimates that this lateral capacity would be sufficient to enable each unit to achieve 40 percent natural gas co-firing on an annual average basis.

The EPA considered the availability of the upstream natural gas pipeline capacity to satisfy the assumed co-firing demand implied by these new laterals. This analysis included pipeline development at all EGUs that could be included in this subcategory, including those without announced plans to cease operating before January 1, 2039. The EPA's assessment reviewed the reasonableness of each assumed new lateral by determining whether the peak gas capacity of that lateral could be satisfied without modification of the transmission pipeline systems to which it is assumed to be connected. This analysis found that most, if not all, existing pipeline systems are currently able to meet the peak needs implied by these new laterals in aggregate, assuming that each existing coal-fired unit in the analysis co-fired with natural gas at a level implied by these new laterals, or 60 percent of net summer generating capacity. While this is a reasonable assumption for the analysis to support this mitigation measure in the BSER context, it is also a conservative assumption that overstates the amount of natural gas co-firing expected under the final rule.[681]

Most of these individual laterals are less than 15 miles in length. The maximum aggregate amount of pipeline capacity, if all coal-fired steam capacity that could be included in the medium-term subcategory (*i.e.,* all capacity that has not announced that it plans to retire by 2032) implemented the final BSER by co-firing 40 percent natural gas, would be comparable to pipeline capacity constructed recently. The EPA estimates that this maximum total capacity would be nearly 14.7 billion cubic feet per day, which would require about 3,500 miles of pipeline costing roughly $11.5 billion. Over 2 years,[682] this maximum total incremental pipeline capacity would amount to less than 1,800 miles per year, with a total annual capacity of roughly 7.35 billion cubic feet per day. This represents an estimated annual investment of approximately $5.75 billion per year in capital expenditures, on average. By comparison, based on data collected by EIA, the total annual mileage of natural gas pipelines constructed over the 2017–2021 period ranged from approximately 1,000 to 2,500 miles per year, with a total annual capacity of 10 to 25 billion cubic feet per day. This represents an estimated annual investment of up to nearly $15 billion. The upper end of these historical annual values is much higher than the maximum annual values that could be expected under this final BSER measure—which, as noted above, represent a conservative estimate that significantly overstates the amount of co-firing that the EPA projects would occur under this final rule.

These conservatively high estimates of pipeline requirements also compare favorably to industry projections of future pipeline capacity additions. Based on a review of a 2018 industry report, titled ''North America Midstream Infrastructure through 2035: Significant Development Continues,'' investment in midstream infrastructure development is expected to range between $10 to $20 billion per year through 2035. Approximately $5 to $10 billion annually is expected to be invested in natural gas pipelines through 2035. This report also projects that an average of over 1,400 miles of new natural gas pipeline will be built through 2035, which is similar to the approximately 1,670 miles that were built on average from 2013 to 2017. These values are consistent with the average annual expenditure of $5.75 billion on less than 1,800 miles per year of new pipeline construction that would be necessary for the entire operational fleet of existing coal-fired steam generating units to co-fire with natural gas. The actual pipeline investment for this subcategory would be substantially lower.

(C) Compliance Date for Medium-Term Coal-Fired Steam Generating Units

The EPA is finalizing a compliance date for medium-term coal-fired steam generating units of January 1, 2030.

As in the timeline for CCS for the long term coal-fired steam generating units described in section VII.C.1.a.i(E), the EPA assumes here that feasibility work occurs during the state plan development period, and that all subsequent work occurs after the state plan is submitted and thereby effective at the state level. The EPA assumes 12 months of feasibility work for the natural gas pipeline lateral and 6 months of feasibility work for boiler modifications (both to occur over June 2024 to June 2025). As with the feasibility analysis for CCS, the feasibility analysis for co-firing will inform the state plan and therefore it is reasonable to assume units will perform it during the state planning window. Feasibility for the pipeline includes a right-of-way and routing analysis. Feasibility for the boiler modifications includes conceptual studies and design basis.

The timeline for the natural gas pipeline permitting and construction is based on a review of recently completed permitting approvals and construction.[683] The average time to complete permitting and approval is less than 1.5 years, and the average time to complete actual construction is less than 1 year. Of the 31 reviewed pipeline projects, the vast majority (27 projects) took less than a total of 3 years for permitting and construction, and none took more than 3.5 years. Therefore, it is reasonable to assume that permitting and construction would take no more than 3 years for most sources (June 2026 to June 2029), noting that permitting

[681] In practice, not all sources would necessarily be subject to a natural gas co-firing BSER in compliance. *E.g.,* some portion of that population of sources could install CCS, so the resulting amount of natural gas co-firing would be less.

[682] The average time for permitting for a natural gas pipeline lateral is 1.5 years, and many sources could be permitted faster (about 1 year) so that it is reasonable to assume that many sources could begin construction by June 2027. The average time for construction of an individual pipeline is about 1 year or less. Considering this, the EPA assumes construction of all of the natural gas pipeline laterals in the analysis occurs over a 2-year period (June 2027 through June 2029), and notes that in practice some of these projects could be constructed outside of this period.

[683] Documentation for the Lateral Cost Estimation (2024), ICF International. Available in Docket ID EPA–HQ–OAR–2023–0072.

and construction for many sources would be faster.

The timeline for boiler modifications based on the baseline duration co-firing conversion project schedule developed by Sargent and Lundy.[684] The EPA assumes that, with the exception of the feasibility studies discussed above, work on the boiler modifications begins after the state plan submission due date. The EPA also assumes permitting for the boiler modifications is required and takes 12 months (June 2026 to June 2027). In the schedule developed by Sargent and Lundy, commercial arrangements for the boiler modification take about 6 months (June 2026 to December 2026). Detailed engineering and procurement takes about 7 months (December 2026 to July 2027), and begins after commercial arrangements are complete. Site work takes 3 months (July 2027 to October 2027), followed by 4 months of construction (October 2027 to February 2028). Lastly, startup and testing takes about 2 months (June 2029 to August 2029), noting that the EPA assumes this occurs after the natural gas pipeline lateral is constructed. Considering the preceding information, the EPA has determined January 1, 2030 is the compliance date for medium-term coal-fired steam generating units.

ii. Costs

The capital costs associated with the addition of new gas burners and other necessary boiler modifications depend on the extent to which the current boiler is already able to co-fire with some natural gas and on the amount of gas co-firing desired. The EPA estimates that, on average, the total capital cost associated with modifying existing boilers to operate at up to 100 percent of heat input using natural gas is approximately $52/kW. These costs could be higher or lower, depending on the equipment that is already installed and the expected impact on heat rate or steam temperature.

While fixed O&M (FOM) costs can potentially decrease as a result of decreasing the amount of coal consumed, it is common for plants to maintain operation of one coal pulverizer at all times, which is necessary for maintaining several coal burners in continuous service. In this case, coal handling equipment would be required to operate continuously and therefore natural gas co-firing would have limited effect on reducing the coal-related FOM costs. Although, as noted, coal-related FOM costs have the potential to decrease, the EPA does not anticipate a significant increase in impact on FOM costs related to co-firing with natural gas.

In addition to capital and FOM cost impacts, any additional natural gas co-firing would result in incremental costs related to the differential in fuel cost, taking into consideration the difference in delivered coal and gas prices, as well as any potential impact on the overall net heat rate. The EPA's reference case projects that in 2030, the average delivered price of coal will be $1.56/MMBtu and the average delivered price of natural gas will be $2.95/MMBtu. Thus, assuming the same level of generation and no impact on heat rate, the additional fuel cost would be $1.39/MMBtu on average in 2030. The total additional fuel cost could increase or decrease depending on the potential impact on net heat rate. An increase in net heat rate, for example, would result in more fuel required to produce a given amount of generation and thus additional cost. In the final TSD, *GHG Mitigation Measures for Steam Generating Units,* the EPA's cost estimates assume a 1 percent average increase in net heat rate.

Finally, for plants without sufficient access to natural gas, it is also necessary to construct new natural gas pipelines (''laterals''). Pipeline costs are typically expressed in terms of dollars per inch of pipeline diameter per mile of pipeline distance (*i.e.,* dollars per inch-mile), reflecting the fact that costs increase with larger diameters and longer pipelines. On average, the cost for lateral development within the contiguous U.S. is approximately $280,000 per inch-mile (2019$), which can vary based on site-specific factors. The total pipeline cost for each coal-fired steam generating unit is a function of this cost, as well as a function of the necessary pipeline capacity and the location of the plant relative to the existing pipeline transmission network. The pipeline capacity required depends on the amount of co-firing desired as well as on the desired level of generation—a higher degree of co-firing while operating at full load would require more pipeline capacity than a lower degree of co-firing while operating at partial load. It is reasonable to assume that most plant owners would develop sufficient pipeline capacity to deliver the maximum amount of desired gas use in any moment, enabling higher levels of co-firing during periods of lower fuel price differentials. Once the necessary pipeline capacity is determined, the total lateral cost can be estimated by considering the location of each plant relative to the existing natural gas transmission pipelines as well as the available excess capacity of each of those existing pipelines.

The EPA determined the costs of 40 percent co-firing based on the fleet of coal-fired steam generating units that existed in 2021 and that do not have known plans to cease operations or convert to gas by 2032, and assuming that each of those units continues to operate at the same level as it operated over 2017–2021. The EPA assessed those costs against the cost reasonableness metrics, as described in section VII.C.1.a.ii(D) of this preamble (*i.e.,* emission control costs on EGUs of $10.60 to $18.50/MWh and the costs in the 2016 NSPS regulating GHGs for the Crude Oil and Natural Gas source category of $98/ton of CO_{2e} reduced (80 FR 56627; September 18, 2015)). On average, the EPA estimates that the weighted average cost of co-firing with 40 percent natural gas as the BSER on an annual average basis is approximately $73/ton CO_2 reduced, or $13/MWh. The costs here reflect an amortization period of 9 years. These estimates support a conclusion that co-firing is cost-reasonable for sources that continue to operate up until the January 1, 2039, threshold date for the subcategory. The EPA also evaluated the fleet average costs of natural gas co-firing for shorter amortization periods and has determined that the costs are consistent with the cost reasonableness metrics for the majority of sources that will operate past January 1, 2032, and therefore have an amortization period of at least 2 years and up to 9 years. These estimates and all underlying assumptions are explained in detail in the final TSD, *GHG Mitigation Measures for Steam Generating Units.* Based on this cost analysis, alongside the EPA's overall assessment of the costs of this rule, the EPA is finalizing that the costs of natural gas co-firing are reasonable for the medium-term coal-fired steam generating unit subcategory. If a particular source has costs of 40 percent co-firing that are fundamentally different from the cost reasonability metrics, the state may consider this fact under the RULOF provisions, as detailed in section X.C.2 of this preamble. The EPA previously estimated the cost of natural gas co-firing in the Clean Power Plan (CPP). 80 FR 64662 (October 23, 2015). The cost-estimates for co-firing presented in this section are lower than in the CPP, for several reasons. Since then, the expected difference between coal and gas prices has decreased significantly, from over $3/MMBtu to less than $1.50/MMBtu in this final rule. Additionally,

[684] Natural Gas Co-Firing Memo, Sargent & Lundy (2023). Available in Docket ID EPA–HQ–OAR–2023–0072.

a recent analysis performed by Sargent and Lundy for the EPA supports a considerably lower capital cost for modifying existing boilers to co-fire with natural gas. The EPA also recently conducted a highly detailed facility-level analysis of natural gas pipeline costs, the median value of which is slightly lower than the value used by the EPA previously to approximate the cost of co-firing at a representative unit.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Natural gas co-firing for steam generating units is not expected to have any significant adverse consequences related to non-air quality health and environmental impacts or energy requirements.

(A) Non-GHG Emissions

Non-GHG emissions are reduced when steam generating units co-fire with natural gas because less coal is combusted. SO_2, $PM_{2.5}$, acid gas, mercury and other hazardous air pollutant emissions that result from coal combustion are reduced proportionally to the amount of natural gas consumed, *i.e.,* under this final rule, by 40 percent. Natural gas combustion does produce NO_X emissions, but in lesser amounts than from coal-firing. However, the magnitude of this reduction is dependent on the combustion system modifications that are implemented to facilitate natural gas co-firing.

Sufficient regulations also exist related to natural gas pipelines and transport that assure natural gas can be safely transported with minimal risk of environmental release. PHMSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.6 million mile pipeline transportation system. Recently, PHMSA finalized a rule that will improve the safety and strengthen the environmental protection of more than 300,000 miles of onshore gas transmission pipelines.[685] PHMSA also recently promulgated a separate rule covering natural gas transmission,[686] as well as a rule that significantly expanded the scope of safety and reporting requirements for more than 400,000 miles of previously unregulated gas gathering lines.[687] FERC is responsible for the regulation of the siting, construction, and/or abandonment of interstate natural gas pipelines, gas storage facilities, and Liquified Natural Gas (LNG) terminals.

(B) Energy Requirements

The introduction of natural gas co-firing will cause steam boilers to be slightly less efficient due to the high hydrogen content of natural gas. Co-firing at levels between 20 percent and 100 percent can be expected to decrease boiler efficiency between 1 percent and 5 percent. However, despite the decrease in boiler efficiency, the overall net output efficiency of a steam generating unit that switches from coal- to natural gas-firing may change only slightly, in either a positive or negative direction. Since co-firing reduces coal consumption, the auxiliary power demand related to coal handling and emissions controls typically decreases as well. While a site-specific analysis would be required to determine the overall net impact of these countervailing factors, generally the effect of co-firing on net unit heat rate can vary within approximately plus or minus 2 percent.

The EPA previously determined in the ACE Rule (84 FR 32545; July 8, 2019) that ''co-firing natural gas in coal-fired utility boilers is not the best or most efficient use of natural gas and [. . .] can lead to less efficient operation of utility boilers.'' That determination was informed by the more limited supply of natural gas, and the larger amount of coal-fired EGU capacity and generation, in 2019. Since that determination, the expected supply of natural gas has expanded considerably, and the capacity and generation of the existing coal-fired fleet has decreased, reducing the total mass of natural gas that might be required for sources to implement this measure.

Furthermore, regarding the efficient operation of boilers, the ACE determination was based on the observation that ''co-firing can negatively impact a unit's heat rate (efficiency) due to the high hydrogen content of natural gas and the resulting production of water as a combustion by-product.'' That finding does not consider the fact that the effect of co-firing on net unit heat rate can vary within approximately plus or minus 2 percent, and therefore the net impact on overall utility boiler efficiency for each steam generating unit is uncertain.

For all of these reasons, the EPA is finalizing that natural gas co-firing at medium-term coal-fired steam generating units does not result in any significant adverse consequences related to energy requirements.

Additionally, the EPA considered longer term impacts on the energy sector, and the EPA is finalizing these impacts are reasonable. Designating natural gas co-firing as the BSER for medium-term coal-fired steam generating units would not have significant adverse impacts on the structure of the energy sector. Steam generating units that currently are coal-fired would be able to remain primarily coal-fired. The replacement of some coal with natural gas as fuel in these sources would not have significant adverse effects on the price of natural gas or the price of electricity.

iv. Extent of Reductions in CO_2 Emissions

One of the primary benefits of natural gas co-firing is emission reduction. CO_2 emissions are reduced by approximately 4 percent for every additional 10 percent of co-firing. When moving from 100 percent coal to 60 percent coal and 40 percent natural gas, CO_2 stack emissions are reduced by approximately 16 percent. Non-CO_2 emissions are reduced as well, as noted earlier in this preamble.

v. Technology Advancement

Natural gas co-firing is already well-established and widely used by coal-fired steam boiler generating units. As a result, this final rule is not likely to lead to technological advances or cost reductions in the components of natural gas co-firing, including modifications to boilers and pipeline construction. However, greater use of natural gas co-firing may lead to improvements in the efficiency of conducting natural gas co-firing and operating the associated equipment.

c. Options Not Determined To Be the BSER for Medium-Term Coal-Fired Steam Generating Units

i. CCS

As discussed earlier in this preamble, the compliance date for CCS is January 1, 2032. Accordingly, sources in the medium-term subcategory—which have elected to commit to permanently cease operations prior to 2039—would have less than 7 years to amortize the capital costs of CCS. As a result, for these sources, the overall costs of CCS would exceed the metrics for cost reasonableness that the EPA is using in

[685] Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (87 FR 52224; August 24, 2022).

[686] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (84 FR 52180; October 1, 2019).

[687] Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments (86 FR 63266; November 15, 2021).

this rulemaking, which are detailed in section VII.C.1.a.ii(D). For this reason, the EPA is not finalizing CCS as the BSER for the medium-term subcategory.

ii. Heat Rate Improvements

Heat rate improvements were not considered to be BSER for medium-term steam generating units because the achievable reductions are low and may result in rebound effect whereby total emissions from the source increase, as detailed in section VII.D.4.a.

d. Conclusion

The EPA is finalizing that natural gas co-firing at 40 percent of heat input is the BSER for medium-term coal-fired steam generating units because natural gas co-firing is adequately demonstrated, as indicated by the facts that it has been operated at scale and is widely applicable to sources. Additionally, the costs for natural gas co-firing are reasonable. Moreover, natural gas co-firing can be expected to reduce emissions of several other air pollutants in addition to GHGs. Any adverse non-air quality health and environmental impacts and energy requirements of natural gas co-firing are limited. In contrast, CCS, although achieving greater emission reductions, would be of higher cost, in general, for the subcategory of medium-term units, and HRI would achieve few reductions and, in fact, may increase emissions.

3. Degree of Emission Limitation for Final Standards

Under CAA section 111(d), once the EPA determines the BSER, it must determine the ''degree of emission limitation'' achievable by the application of the BSER. States then determine standards of performance and include them in the state plans, based on the specified degree of emission limitation. Final presumptive standards of performance are detailed in section X.C.1.b of this preamble. There is substantial variation in emission rates among coal-fired steam generating units—the range is, approximately, from 1,700 lb CO_2/MWh-gross to 2,500 lb CO_2/MWh-gross—which makes it challenging to determine a single, uniform emission limit. Accordingly, the EPA is finalizing the degrees of emission limitation by a percentage change in emission rate, as follows.

a. Long-Term Coal-Fired Steam Generating Units

As discussed earlier in this preamble, the EPA is finalizing the BSER for long-term coal-fired steam generating units as ''full-capture'' CCS, defined as 90 percent capture of the CO_2 in the flue gas. The degree of emission limitation achievable by applying this BSER can be determined on a rate basis. A capture rate of 90 percent results in reductions in the emission rate of 88.4 percent on a lb CO_2/MWh-gross basis, and this reduction in emission rate can be observed over an extended period (*e.g.,* an annual calendar-year basis). Therefore, the EPA is finalizing that the degree of emission limitation for long-term units is an 88.4 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.,* an annual calendar-year basis).

b. Medium-Term Coal-Fired Steam Generating Units

As discussed earlier in this preamble, the BSER for medium-term coal-fired steam generating units is 40 percent natural gas co-firing. The application of 40 percent natural gas co-firing results in reductions in the emission rate of 16 percent. Therefore, the degree of emission limitation for these units is a 16 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period (*e.g.,* an annual calendar-year basis).

D. Rationale for the BSER for Natural Gas-Fired And Oil-Fired Steam Generating Units

This section of the preamble describes the rationale for the final BSERs for existing natural gas- and oil-fired steam generating units based on the criteria described in section V.C of this preamble.

1. Subcategorization of Natural Gas- and Oil-Fired Steam Generating Units

The EPA is finalizing subcategories based on load level (*i.e.,* annual capacity factor), specifically, units that are base load, intermediate load, and low load. The EPA is finalizing routine methods of operation and maintenance as BSER for intermediate and base load units. Applying that BSER would not achieve emission reductions but would prevent increases in emission rates. The EPA is finalizing presumptive standards of performance that differ between intermediate and base load units due to their differences in operation, as detailed in section X.C.1.b.iii of this preamble. The EPA proposed a separate subcategory for non-continental oil-fired steam generating units, which operate differently from continental units; however, the EPA is not finalizing emission guidelines for sources outside of the contiguous U.S., as described in section VII.B. At proposal, the EPA solicited comment on a BSER of ''uniform fuels'' for low load natural gas- and oil-fired steam generating units, and the EPA is finalizing this approach for those sources.

Natural gas- and oil-fired steam generating units combust natural gas or distillate fuel oil or residual fuel oil in a boiler to produce steam for a turbine that drives a generator to create electricity. In non-continental areas, existing natural gas- and oil-fired steam generating units may provide base load power, but in the continental U.S., most existing units operate in a load-following manner. There are approximately 200 natural gas-fired steam generating units and fewer than 30 oil-fired steam generating units in operation in the continental U.S. Fuel costs and inefficiency relative to other technologies (*e.g.,* combustion turbines) result in operation at lower annual capacity factors for most units. Based on data reported to EIA and the EPA [688] for the contiguous U.S., for natural gas-fired steam generating units in 2019, the average annual capacity factor was less than 15 percent and 90 percent of units had annual capacity factors less than 35 percent. For oil-fired steam generating units in 2019, no units had annual capacity factors above 8 percent. Additionally, their load-following method of operation results in frequent cycling and a greater proportion of time spent at low hourly capacities, when generation is less efficient. Furthermore, because startup times for most boilers are usually long, natural gas steam generating units may operate in standby mode between periods of peak demand. Operating in standby mode requires combusting fuel to keep the boiler warm, and this further reduces the efficiency of natural gas combustion.

Unlike coal-fired steam generating units, the CO_2 emission rates of oil- and natural gas-fired steam generating units that have similar annual capacity factors do not vary considerably between units. This is partly due to the more uniform qualities (*e.g.,* carbon content) of the fuel used. However, the emission rates for units that have different annual capacity factors do vary considerably, as detailed in the final TSD, *Natural Gas- and Oil-fired Steam Generating Units.* Low annual capacity factor units cycle frequently, have a greater proportion of CO_2 emissions that may be attributed to startup, and have a greater proportion of generation at inefficient hourly capacities. Intermediate annual capacity factor units operate more often at higher hourly capacities, where CO_2 emission rates are lower. High annual capacity factor units operate still more at base load conditions, where units are more

[688] Clean Air Markets Program Data at *https://campd.epa.gov*.

efficient and CO_2 emission rates are lower.

Based on these performance differences between these load levels, the EPA, in general, proposed subcategories based on dividing natural gas- and oil-fired steam generating units into three groups each—low load, intermediate load, and base load.

The EPA is finalizing subcategories for oil-fired and natural gas-fired steam generating units, based on load levels. The EPA proposed the following load levels: ''low'' load, defined by annual capacity factors less than 8 percent; ''intermediate'' load, defined by annual capacity factors greater than or equal to 8 percent and less than 45 percent; and ''base'' load, defined by annual capacity factors greater than or equal to 45 percent.

The EPA is finalizing January 1, 2030, as the compliance date for natural gas- and oil-fired steam generating units and this date is consistent with the dates in the fuel type definitions.

The EPA received comments that were generally supportive of the proposed subcategory definitions,[689] and the EPA is finalizing the subcategory definitions as proposed.

2. Options Considered for BSER

The EPA has considered various methods for controlling CO_2 emissions from natural gas- and oil-fired steam generating units to determine whether they meet the criteria for BSER. Co-firing natural gas cannot be the BSER for these units because natural gas- and oil-fired steam generating units already fire large proportions of natural gas. Most natural gas-fired steam generating units fire more than 90 percent natural gas on a heat input basis, and any oil-fired steam generating units that would potentially operate above an annual capacity factor of around 15 percent typically combust natural gas as a large proportion of their fuel as well. Nor is CCS a candidate for BSER. The utilization of most gas-fired units, and likely all oil-fired units, is relatively low, and as a result, the amount of CO_2 available to be captured is low. However, the capture equipment would still need to be sized for the nameplate capacity of the unit. Therefore, the capital and operating costs of CCS would be high relative to the amount of CO_2 available to be captured. Additionally, again due to lower utilization, the amount of IRC section 45Q tax credits that owner/operators could claim would be low. Because of the relatively high costs and the relatively low cumulative emission reduction potential for these natural gas- and oil-fired steam generating units, the EPA is not determining CCS as the BSER for them.

The EPA has reviewed other possible controls but is not finalizing any of them as the BSER for natural gas- and oil-fired units either. Co-firing hydrogen in a boiler is technically possible, but there is limited availability of hydrogen now and in the near future and it should be prioritized for more efficient units. Additionally, for natural gas-fired steam generating units, setting a future standard based on hydrogen would likely have limited GHG reduction benefits given the low utilization of natural gas- and oil-fired steam generating units. Lastly, HRI for these types of units would face many of the same issues as for coal-fired steam generating units; in particular, HRI could result in a rebound effect that would increase emissions.

However, the EPA recognizes that natural gas- and oil-fired steam generating units could possibly, over time, operate more, in response to other changes in the power sector. Additionally, some coal-fired steam generating units have converted to 100 percent natural gas-fired, and it is possible that more may do so in the future. The EPA also received several comments from industry stating plans to do so. Moreover, in part because the fleet continues to age, the plants may operate with degrading emission rates. In light of these possibilities, identifying the BSER and degrees of emission limitation for these sources would be useful to provide clarity and prevent backsliding in GHG performance. Therefore, the EPA is finalizing BSER for intermediate and base load natural gas- and oil-fired steam generating units to be routine methods of operation and maintenance, such that the sources could maintain the emission rates (on a lb/MWh-gross basis) currently maintained by the majority of the fleet across discrete ranges of annual capacity factor. The EPA is finalizing this BSER for intermediate load and base load natural gas- and oil-fired steam generating units, regardless of the operating horizon of the unit.

A BSER based on routine methods of operation and maintenance is adequately demonstrated because units already operate with those practices. There are no or negligible additional costs because there is no additional technology that units are required to apply and there is no change in operation or maintenance that units must perform. Similarly, there are no adverse non-air quality health and environmental impacts or adverse impacts on energy requirements. Nor do they have adverse impacts on the energy sector from a nationwide or long-term perspective. The EPA's modeling, which supports this final rule, indicates that by 2040, a number of natural gas-fired steam generating units will have remained in operation since 2030, although at reduced annual capacity factors. There are no CO_2 reductions that may be achieved at the unit level, but applying routine methods of operation and maintenance as the BSER prevents increases in emission rates. Routine methods of operation and maintenance do not advance useful control technology, but this point is not significant enough to offset their benefits.

At proposal, the EPA also took comment on a potential BSER of uniform fuels for low load natural gas- and oil-fired steam generating units. As noted earlier in this preamble, non-coal fossil fuels combusted in utility boilers typically include natural gas, distillate fuel oil (*i.e.,* fuel oil No. 1 and No. 2), and residual fuel oil (*i.e.,* fuel oil No. 5 and No. 6). The EPA previously established heat-input based fuel composition as BSER in the 2015 NSPS (termed ''clean fuels'' in that rulemaking) for new non-base load natural gas- and multi-fuel-fired stationary combustion turbines (80 FR 64615–17; October 23, 2015), and the EPA is similarly finalizing lower-emitting fuels as BSER for new low load combustion turbines as described in section VIII.F of this preamble. For low load natural gas- and oil-fired steam generating units, the high variability in emission rates associated with the variability of load at the lower-load levels limits the benefits of a BSER based on routine maintenance and operation. That is because the high variability in emission rates would make it challenging to determine an emission rate (*i.e.,* on a lb CO_2/MWh-gross basis) that could serve as the presumptive standard of performance that would reflect application of a BSER of routine operation and maintenance. On the other hand, for those units, a BSER of ''uniform fuels'' and an associated presumptive standard of performance based on a heat input basis, as described in section X.C.1.b.iii of this preamble, is reasonable. Therefore, the EPA is finalizing a BSER of uniform fuels for low load natural gas- and oil-fired steam generating units, with presumptive standards depending on fuel type detailed in section X.C.1.b.iii.

[689] See, for example, Document ID No. EPA–HQ–OAR–2023–0072–0583.

3. Degree of Emission Limitation

As discussed above, because the BSER for base load and intermediate load natural gas- and oil-fired steam generating units is routine operation and maintenance, which the units are, by definition, already employing, the degree of emission limitation by application of this BSER is no increase in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*e.g.,* a year).

For low load natural gas- and oil-fired steam generating units, the EPA is finalizing a BSER of uniform fuels, with a degree of emission limitation on a heat input basis consistent with a fixed 130 lb CO_2/MMBtu for natural gas-fired steam generating units and 170 lb CO_2/MMBtu for oil-fired steam generating units. The degree of emission limitation for natural gas- and oil-fired steam generating units is higher than the corresponding values under 40 CFR part 60, subpart TTTT, because steam generating units may fire fuels with slightly higher carbon contents.

4. Other Emission Reduction Measures Not Considered BSER

a. Heat Rate Improvements

Heat rate is a measure of efficiency that is commonly used in the power sector. The heat rate is the amount of energy input, measured in Btu, required to generate 1 kilowatt-hour (kWh) of electricity. The lower an EGU's heat rate, the more efficiently it operates. As a result, an EGU with a lower heat rate will consume less fuel and emit lower amounts of CO_2 and other air pollutants per kWh generated as compared to a less efficient unit. HRI measures include a variety of technology upgrades and operating practices that may achieve CO_2 emission rate reductions of 0.1 to 5 percent for individual EGUs. The EPA considered HRI to be part of the BSER in the CPP and to be the BSER in the ACE Rule. However, the reductions that may be achieved by HRI are small relative to the reductions from natural gas co-firing and CCS. Also, some facilities that apply HRI would, as a result of their increased efficiency, increase their utilization and therefore increase their CO_2 emissions (as well as emissions of other air pollutants), a phenomenon that the EPA has termed the ''rebound effect.'' Therefore, the EPA is not finalizing HRI as a part of BSER.

i. CO_2 Reductions From HRI in Prior Rulemakings

In the CPP, the EPA quantified emission reductions achievable through heat rate improvements on a regional basis by an analysis of historical emission rate data, taking into consideration operating load and ambient temperature. The Agency concluded that EGUs can achieve on average a 4.3 percent improvement in the Eastern Interconnection, a 2.1 percent improvement in the Western Interconnection, and a 2.3 percent improvement in the Texas Interconnection. See 80 FR 64789 (October 23, 2015). The Agency then applied all three of the building blocks to 2012 baseline data and quantified, in the form of CO_2 emission rates, the reductions achievable in Each interconnection in 2030, and then selected the least stringent as a national performance rate. *Id.* at 64811–19. The EPA noted that building block 1 measures could not by themselves constitute the BSER because the quantity of emission reductions achieved would be too small and because of the potential for an increase in emissions due to increased utilization (*i.e.,* the ''rebound effect'').

ii. Updated CO_2 Reductions From HRI

The HRI measures include improvements to the boiler island (*e.g.,* neural network system, intelligent sootblower system), improvements to the steam turbine (*e.g.,* turbine overhaul and upgrade), and other equipment upgrades (*e.g.,* variable frequency drives). Some regular practices that may recover degradation in heat rate to recent levels—but that do not result in upgrades in heat rate over recent design levels and are therefore not HRI measures—include practices such as in-kind replacements and regular surface cleaning (*e.g.,* descaling, fouling removal). Specific details of the HRI measures are described in the final TSD, *GHG Mitigation Measures for Steam Generating Units* and an updated 2023 Sargent and Lundy HRI report (*Heat Rate Improvement Method Costs and Limitations Memo*), available in the docket. Most HRI upgrade measures achieve reductions in heat rate of less than 1 percent. In general, the 2023 Sargent and Lundy HRI report, which updates the 2009 Sargent and Lundy HRI report, shows that HRI achieve less reductions than indicated in the 2009 report, and shows that several HRI either have limited applicability or have already been applied at many units. Steam path overhaul and upgrade may achieve reductions up to 5.15 percent, with the average being around 1.5 percent. Different combinations of HRI measures do not necessarily result in cumulative reductions in emission rate (*e.g.,* intelligent sootblowing systems combined with neural network systems). Some of the HRI measures (*e.g.,* variable frequency drives) only impact heat rate on a net generation basis by reducing the parasitic load on the unit and would thereby not be observable for emission rates measured on a gross basis. Assuming many of the HRI measures could be applied to the same unit, adding together the upper range of some of the HRI percentages could yield an emission rate reduction of around 5 percent. However, the reductions that the fleet could achieve on average are likely much smaller. As noted, the 2023 Sargent and Lundy HRI report notes that, in many cases, units have already applied HRI upgrades or that those upgrades would not be applicable to all units. The unit level reductions in emission rate from HRI are small relative to CCS or natural gas co-firing. In the CPP and ACE Rule, the EPA viewed CCS and natural gas co-firing as too costly to qualify as the BSER; those costs have fallen since those rules and, as a result, CCS and natural gas co-firing do qualify as the BSER for the long-term and medium-term subcategories, respectively.

iii. Potential for Rebound in CO_2 Emissions

Reductions achieved on a rate basis from HRI may not result in overall emission reductions and could instead cause a ''rebound effect'' from increased utilization. A rebound effect would occur where, because of an improvement in its heat rate, a steam generating unit experiences a reduction in variable operating costs that makes the unit more competitive relative to other EGUs and consequently raises the unit's output. The increase in the unit's CO_2 emissions associated with the increase in output would offset the reduction in the unit's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of output. The extent of the offset would depend on the extent to which the unit's generation increased. The CPP did not consider HRI to be BSER on its own, in part because of the potential for a rebound effect. Analysis for the ACE Rule, where HRI was the entire BSER, observed a rebound effect for certain sources in some cases.[690] In this action, where different subcategories of units are to be subject to different BSER measures, steam generating units in a hypothetical subcategory with HRI as BSER could experience a rebound effect. Because of this potential for perverse GHG emission outcomes resulting from deployment of HRI at certain steam generating units, coupled with the

[690] 84 FR 32520 (July 8, 2019).

relatively minor overall GHG emission reductions that would be expected from this measure, the EPA is not finalizing HRI as the BSER for any subcategory of existing coal-fired steam generating units.

E. Additional Comments Received on the Emission Guidelines for Existing Steam Generating Units and Responses

1. Consistency With West Virginia v. EPA and the Major Questions Doctrine

Comment: Some commenters argued that the EPA's determination that CCS is the BSER for existing coal-fired power plants is invalid under *West Virginia* v. *EPA,* 597 U.S. 697 (2022), and the major questions doctrine (MQD). Commenters state that for various reasons, coal-fired power plants will not install CCS and instead will be forced to retire their units. They point to the EPA's IPM modeling which, they say, shows that many coal-fired power plants retire rather than install CCS. They add that, in this way, the rule effectively results in the EPA's requiring generation-shifting from coal-fired generation to renewable and other generation, and thus is like the Clean Power Plan (CPP). For those reasons, they state that the rule raises a major question, and further that CAA section 111(d) does not contain a clear authorization for this type of rule.

Response: The EPA discussed *West Virginia* and its articulation of the MQD in section V.B.6 of this preamble.

The EPA disagrees with these comments. This rule is fully consistent with the Supreme Court's interpretation of the EPA's authority in *West Virginia.* The EPA's determination that CCS—a traditional, add-on emissions control—is the BSER is consistent with the plain text of section 111. As explained in detail in section VII.C.1.a, for long-term coal-fired steam generating units, CCS meets all of the BSER factors: it is adequately demonstrated, of reasonable cost, and achieves substantial emissions reductions. That some coal-fired power plants will choose not to install emission controls and will instead retire does not raise major questions concerns.

In *West Virginia,* the U.S. Supreme Court held that ''generation-shifting'' as the BSER for coal- and gas-fired units ''effected a fundamental revision of the statute, changing it from one sort of scheme of regulation into an entirely different kind.'' 597 U.S. at 728 (internal quotation marks, brackets, and citation omitted). The Court explained that prior CAA section 111 rules were premised on ''more traditional air pollution control measures'' that ''focus on improving the performance of individual sources.'' *Id.* at 727 (citing ''fuel-switching'' and ''add-on controls''). The Court said that generation-shifting as the BSER was ''unprecedented'' because it was designed to ''improve the overall power system by lowering the carbon intensity of power generation . . . by forcing a shift throughout the power grid from one type of energy source to another.'' *Id.* at 727–28 (internal quotation marks, emphasis, and citation omitted). The Court cited statements by the then-Administrator describing the CPP as ''not about pollution control so much as it was an investment opportunity for States, especially investments in renewables and clean energy.'' *Id.* at 728. The Court further concluded that the EPA's view of its authority was virtually unbounded because the ''EPA decides, for instance, how much of a switch from coal to natural gas is practically feasible by 2020, 2025, and 2030 before the grid collapses, and how high energy prices can go as a result before they become unreasonably exorbitant.'' *Id.* at 729.

Here, the EPA's determination that CCS is the BSER does not affect a fundamental revision of the statute, nor is it unbounded. CCS is not directed at improvement of the overall power system. Rather, CCS is a traditional ''add-on [pollution] control[ ]'' akin to measures that the EPA identified as BSER in prior CAA section 111 rules. *See id.* at 727. It ''focus[es] on improving the performance of individual sources''—it reduces CO_2 pollution from each individual source—because each affected source is able to apply it to its own facility to reduce its own emissions. *Id.* at 727. Further, the EPA determined that CCS qualifies as the BSER by applying the criteria specified in CAA section 111(a)(1)—including adequate demonstration, costs of control, and emissions reductions. *See* section VII.C.1.a of this preamble. Thus, CCS as the BSER does not ''chang[e]'' the statute ''from one sort of scheme of regulation into an entirely different kind.'' *Id.* at 728 (internal quotation marks, brackets, and citation omitted).

Commenters contend that notwithstanding these distinctions, the choice of CCS as the BSER has the *effect* of shifting generation because modeling projections for the rule show that coal-fired generation will become less competitive, and gas-fired and renewable-generated electricity will be more competitive and dispatched more frequently. That some coal-fired sources may retire rather than reduce their CO_2 pollution does not mean that the rule ''represents a transformative expansion [of EPA's] regulatory authority''. *Id.* at 724. To be sure, this rule's determination that CCS is the BSER imposes compliance costs on coal-fired power plants. That sources will incur costs to control their emissions of dangerous pollution is an unremarkable consequence of regulation, which, as the Supreme Court recognized, ''may end up causing an incidental loss of coal's market share.'' *Id.* at 731 n.4.[691] Indeed, ensuring that sources internalize the full costs of mitigating their impacts on human health and the environment is a central purpose of traditional environmental regulation.

In particular, for the power sector, grid operators constantly shift generation as they dispatch electricity from sources based upon their costs. The EPA's IPM modeling, which is based on the costs of the various types of electricity generation, projects these impacts. Viewed as a whole, these projected impacts show that, collectively, coal-fired power plants will likely produce less electricity, and other sources (like gas-fired units and renewable sources) will likely produce more electricity, but this pattern does not constitute a transformative expansion of statutory authority (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends.*)

These projected impacts are best understood by comparing the IPM model's ''base case,'' *i.e.,* the projected electricity generation without any rule in place, to the model's ''policy case,'' *i.e.,* the projected electricity generation expected to result from this rule. The base case projects that many coal-fired units will retire over the next 20 years (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*). Those projected retirements track trends over the past two decades where coal-fired units have retired in high numbers because gas-fired units and renewable sources have become increasingly able to generate lower-cost electricity. As more gas-fired and renewable generation sources deploy in the future, and as coal-fired units continue to age—which results in decreased efficiency and increased costs—the coal-fired units will become increasingly marginal and continue to retire (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends.*) That is true in the absence of this rule. The EPA's modeling results also project that even if the EPA had

[691] As discussed in section VII.C.1.a.ii.(D), the costs of CCS are reasonable based on the EPA's $/MWh and $/ton metrics. As discussed in RTC section 2.16, the total annual costs of this rule are a small fraction of the revenues and capital costs of the electric power industry.

determined BSER for long-term sources to be 40 percent co-firing, which requires significantly less capital investment, and not 90 percent capture CCS, a comparable number of sources would retire instead of installing controls. These results confirm that the primary cause for the projected retirements is the marginal profitability of the sources.

Importantly, the base-case projections also show that some coal-fired units install CCS and run at high capacity factors, in fact, higher than they would have had they not installed CCS. This is because the IRC section 45Q tax credit significantly reduces the variable cost of operation for qualifying sources. This incentivizes sources to increase generation to maximize the tons of CO_2 the CCS equipment captures, and thereby increase the amount of the tax credit they receive. In the ''policy case,'' beginning when the CCS requirement applies in the 2035 model year,[692] some additional coal-fired units will likely install CCS, and also run at high capacity factors, again, significantly higher than they would have without CCS. Other units may retire rather than install emission controls (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*). On balance, the coal-fired units that install CCS collectively generate nearly the same amount of electricity in the 2040 model year as do the group of coal-fired units in the base case.

The policy case also shows that in the 2045 model year, by which time the 12-year period for sources to claim the IRC section 45Q tax credit will have expired, most sources that install CCS retire due to the costs of meeting the CCS-based standards without the benefit of the tax credit. However, in fact, these projected outcomes are far from certain as the modeling results generally do not account for numerous potential changes that may occur over the next 20 or more years, any of which may enable these units to continue to operate economically for a longer period. Examples of potential changes include reductions in the operational costs of CCS through technological improvements, or the development of additional potential revenue streams for captured CO_2 as the market for beneficial uses of CO_2 continues to develop, among other possible changed economic circumstances (including the possible extension of the tax credits). In light of these potential significant developments, the EPA is committing to review and, if appropriate, revise the requirements of this rule by January 1, 2041, as described in section VII.F.

In any event, the modeling projections showing that many sources retire instead of installing controls are in line with the trends for these units in the absence of the rule—as the coal-fired fleet ages and lower-cost alternatives become increasingly available, more operators will retire coal-fired units with or without this rule. In 2045, the average age of coal-fired units that have not yet announced retirement dates or coal-to-gas conversion by 2039 will be 61 years old. And, on average, between 2000 and 2022, even in the absence of this rule, coal-fired units generally retired at 53 years old. Thus, taken as a whole, this rule does not dramatically reduce the expected operating horizon of most coal-fired units. Indeed, for units that install CCS, the generous IRC section 45Q tax credit increases the competitiveness of these units, and it allows them to generate more electricity with greater profit than the sources would otherwise generate if they did not install CCS.

The projected effects of the rule do not show the BSER—here, CCS—is akin to generation shifting, or otherwise represents an expansion of EPA authority with vast political or economic significance. As described above at VII.C.1.a.ii, CCS is an affordable emissions control technology. It is also very effective, reducing CO_2 emissions from coal-fired units by 90 percent, as described in section VII.C.1.a.i. Indeed, as noted, the IRA tax credits make CCS so affordable that coal-fired units that install CCS run at higher capacity factors than they would otherwise.

Considered as a whole, and in context with historical retirement trends, the projected impacts of this rule on coal-fired generating units do not raise MQD concerns. The projected impacts are merely incidental to the CCS control itself—the unremarkable consequence of marginally increasing the cost of doing business in a competitive market. Nor is the rule ''transformative.'' The rule does not ''announce what the market share of coal, natural gas, wind, and solar must be, and then requiring plants to reduce operations or subsidize their competitors to get there.'' 597 U.S. at 731 n.4. As noted above, coal-fired units that install CCS are projected to generate substantial amounts of electricity. The retirements that are projected to occur are broadly consistent with market trends over the past two decades, which show that coal-fired electricity production is generally less economic and less competitive than other forms of electricity production. That is, the retirements that the model predicts under this rule, and the structure of the industry that results, diverge little from the prior rate of retirements of coal-fired units over the past two decades. They also diverge little from the rate of retirements from sources that have already announced that they will retire, or from the additional retirements that IPM projects will occur in the base case (EPA's Power Sector Platform 2023 using IPM; final TSD, *Power Sector Trends*).

As discussed above, because much of the coal-fired fleet is operating on the edge of viability, many sources would retire instead of installing any meaningful CO_2 emissions control—whether CCS, natural gas co-firing, or otherwise. Under commenters' view that such retirements create a major question, *any* form of meaningful regulation of these sources would create a major question and effect a fundamental revision of the statute. That cannot possibly be so. Section 111(d)(1) plainly mandates regulation of these units, which are the biggest stationary source of dangerous CO_2 emissions.

The legislative history for the CAA further makes clear that Congress intended the EPA to promulgate regulations even where emissions controls had economic costs. At the time of the 1970 CAA Amendments, Congress recognized that the threats of air pollution to public health and welfare had grown urgent and severe. Sen. Edmund Muskie (D–ME), manager of the bill and chair of the Public Works Subcommittee on Air and Water Pollution, which drafted the bill, regularly referred to the air pollution problem as a ''crisis.'' As Sen. Muskie recognized, ''Air pollution control will be cheap only in relation to the costs of lack of control.'' [693] The Senate Committee Report for the 1970 CAA Amendments specifically discussed the precursor provision to section 111(d) and noted, ''there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.'' [694] Accordingly, some of the

[692] Under the rule, sources are required to meet their CCS-based standard of performance by January 1, 2032. IPM groups calendar years into 5-year periods, *e.g.,* the 2035 model year and the 2040 model year. January 1, 2032, falls into the 2035 model year.

[693] Sen. Muskie, Sept. 21, 1970, LH 226.

[694] S. Rep. No. 91–1196, at 20 (Sept. 17, 1970), 1970 CAA Legis. Hist. at 420 (discussing section 114 of the Senate Committee bill, which was the basis for CAA section 111(d)). Note that in the 1977 CAA Amendments, the House Committee Report made a similar statement. H.R. Rep. No. 95–294, at 42 (May 12, 1977), 1977 CAA Legis. Hist. at 2509 (discussing a provision in the House Committee bill that became CAA section 122, requiring EPA to

EPA's prior CAA section 111 rulemakings have imposed stringent requirements, at significant cost, in order to achieve significant emission reductions.[695]

Congress's enactment of the IRA and IIJA further shows its view that reducing air pollution—specifically, in those laws, GHG emissions to address climate change—is a high priority. As discussed in section IV.E.1, that law provided funds for DOE grant and loan programs to support CCS, and extended and increased the IRC section 45Q tax credit for carbon capture. It also adopted the Low Emission Electricity Program (LEEP), which allocates funds to the EPA for the express purpose of using CAA regulatory authority to reduce GHG emissions from domestic electricity generation through use of its existing CAA authorities. CAA section 135, added by IRA section 60107. The EPA is promulgating the present rulemaking with those funds. The congressional sponsor of the LEEP made clear that it authorized the type of rulemaking that the EPA is promulgating today: he stated that the EPA may promulgate rulemaking under CAA section 111, based on CCS, to address CO_2 emissions from fossil fuel-fired power plants, which may be ''impactful'' by having the ''incidental effect'' of leading some ''companies . . . to choose to retire such plants. . . .'' [696]

For these reasons, the rule here is consistent with the Supreme Court's decision in *West Virginia.* The selection of CCS as the BSER for existing coal-fired units is a traditional, add-on control intended to reduce the emissions performance of individual sources. That some sources may retire instead of controlling their emissions does not otherwise show that the rule runs afoul of the MQD. The modeling projections for this rule show that the anticipated retirements are largely consistent with historical trends, and due to many coal-fired units' advanced age and lack of competitiveness with lower cost methods of electricity generation.

2. Redefining the Source

Comment: Some commenters contended that the proposed 40 percent natural gas co-firing performance standard violates legal precedent that bars the EPA from setting technology-based performance standards that would have the effect of ''redefining the source.'' They stated that this prohibition against the redefinition of the source bars the EPA from adopting the proposed performance standard for medium-term coal-fired EGUs, which requires such units to operate in a manner for which the unit was never designed to do, namely operate as a hybrid coal/natural gas co-firing generating unit and combusting 40 percent of its fuel input as natural gas (instead of coal) on an annual basis.

Commenters argued that co-firing would constitute forcing one type of source to become an entirely different kind of source, and that the Supreme Court precluded such a requirement in *West Virginia* v. *EPA* when it stated in footnote 3 of that case that the EPA has ''never ordered anything remotely like'' a rule that would ''simply require coal plants to become natural gas plants'' and the Court ''doubt[ed that EPA] could.'' [697]

Response: The EPA disagrees with these comments.

Standards based on co-firing, as contemplated in this rule, are based on a ''traditional pollution control measure,'' in particular, ''fuel switching,'' as the Supreme Court recognized in *West Virginia.*[698] Rules based on switching to a cleaner fuel are authorized under the CAA, an authorization directly acknowledged by Congress. Specifically, as part of the 1977 CAA Amendments, Congress required that the EPA base its standards regulating certain new sources, including power plants, on ''technological'' controls, rather than simply the ''best system.'' [699] Congress understood this to mean that new sources would be required to implement add-on controls, rather than merely relying on fuel switching, and noted that one of the purposes of this amendment was to allow new sources to burn high sulfur coal while still decreasing emissions, and thus to increase the availability of low sulfur coal for existing sources, which were not subject to the ''technological'' control requirement.[700] In 1990, however, Congress removed the ''technological'' language, allowing the EPA to set fuel-switching based standards for both new and existing power plants.[701]

The EPA has a tradition of promulgating rules based on fuel switching. For example, the 2006 NSPS for stationary compression ignition internal combustion engines required the use of ultra-low sulfur diesel.[702] Similarly, in the 2015 NSPS for EGUs,[703] the EPA determined that the BSER for peaking plants was to burn primarily natural gas, with distillate oil used only as a backup fuel.[704] Nor is this approach unique to CAA section 111; in the 2016 rule setting section 112 standards for hazardous air pollutant emissions from area sources, for example, the EPA finalized an alternative particulate matter (PM) standard that specified that certain oil-fired boilers would meet the applicable

study and then take action to regulate radioactive air pollutants and three other air pollutants).

[695] *See Sierra Club* v. *Costle,* 657 F.2d 298, 313 (D.C. Cir. 1981) (upholding NSPS imposing controls on SO_2 emissions from coal-fired power plants when the ''cost of the new controls . . . is substantial. EPA estimates that utilities will have to spend tens of billions of dollars by 1995 on pollution control under the new NSPS.'').

[696] 168 Cong. Rec. E868 (August 23, 2022) (statement of Rep. Frank Pallone, Jr.); *id.* E879 (August 26, 2022) (statement of Rep. Frank Pallone, Jr.).

[697] West Virginia v. EPA, 597 U.S, 697, 728 n.3 (2022).

[698] See 597 U.S. at 727.

[699] In 1977, Congress clarified that for purposes of CAA section 111(a)(1)(A), concerning standards of performance for new and modified ''fossil fuel-fired stationary sources'' a standard or performance ''shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best *technological* system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' Clean Air Act 1977 Revisions (emphasis added).

[700] *See* H. Rep. No. 94–1175, 94th Cong., 2d Sess. (May 15, 1976) Part A, at 159 (listing the various purposes of the amendment to Section 111 adding the term 'technological': ''Fourth, by using best control technology on large new fuel-burning stationary sources, these sources could burn higher sulfur fuel than if no technological means of reducing emissions were used. This means an expansion of the energy resources that could be burned in compliance with environmental requirements. Fifth, since large new fuel-burning sources would not rely on naturally low sulfur coal or oil to achieve compliance with new source performance standards, the low sulfur coal or oil that would have been burned in these major new sources could instead be used in older and smaller sources.'')

[701] In 1990, Congress removed this reference to a ''technological system'', and the current text reads simply: ''The term ''standard of performance'' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' 42 U.S.C. 7411(a)(1).

[702] Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 71 FR 39154 (July 11, 2006). In the preamble to the final rule, the EPA noted that for engines which had not previously used this new ultra-low sulfur fuel, additives would likely need to be added to the fuel to maintain appropriate lubricity. *See id.* at 39158.

[703] Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 FR 64510, (October 23, 2015).

[704] *See id.* at 64621.

standard if they combusted only ultra-low-sulfur liquid fuel.[705]

Moreover, the *West Virginia* Court's statements in footnote 3 are irrelevant to the question of the validity of a 40 percent co-firing standard. There, the Court was referring to a complete transformation of the coal-fired unit to a 100 percent gas fired unit—a change that would require entirely repowering the unit. By contrast, increasing co-firing at existing coal-fired units to 40 percent would require only minor changes to the units' boilers. In fact, many coal-fired units are already capable of co-firing some amount of gas without any changes at all, and several have fired at 40 percent and above in recent years. Of the 565 coal-fired EGUs operating at the end of 2021, 249 of them reported consuming natural gas as a fuel or startup source, 162 reported more than one month of consumption of natural gas at their boiler, and 29 co-fired at over 40 percent on an annual heat input basis in at least one year while also operating with annual capacity factors greater than 10 percent. For more on this, see section IV.C.2 of this preamble; see also the final TSD, *GHG Mitigation Measures for Steam Generating Units.*

F. Commitment To Review and, If Appropriate, Revise Emission Guidelines for Coal-Fired Units

The EPA recognizes that the IRC 45Q tax credit is a key component to the cost of CCS, as discussed in section VII.C.1.a.ii(C) of this preamble. The EPA further recognizes that for any affected source, the tax credit is currently available for a 12-year period and not subsequently. The tax credit is generally sufficient to defray the capital costs of CCS and much, if not all, of the operating costs during that 12-year period. Following the 12-year period, affected sources that continue to operate the CCS equipment would have higher costs of generation, due to the CCS operating costs, including parasitic load. Under certain circumstances, these higher costs could push the affected sources lower on the dispatch curve, and thereby lead to reductions in the amount of their generation, *i.e.,* if affected sources are not able to replace the revenue from the tax credit with revenue from other sources, or if the price of electricity does not reflect any additional costs needed to minimize GHG emissions.

However, the costs of CCS and the overall economic viability of operating CO_2 capture at power plants are improving and can be expected to continue to improve in years to come. CO_2 that is captured from fossil-fuel fired sources is currently beneficially used, including, for example, for enhanced oil recovery and in the food and beverage industry. There is much research into developing beneficial uses for many other industries, including construction, chemical manufacturing, graphite manufacturing. The demand for CO_2 is expected to grow considerably over the next several decades. As a result, in the decades to come, affected sources may well be able to replace at least some of the revenues from the tax credit with revenues from the sale of CO_2. We discuss these potential developments in chapter 2 of the Response to Comments document, available in the rulemaking docket.

In addition, numerous states have imposed requirements to decarbonize generation within their borders. Many utilities have also announced plans to decarbonize their fleet, including building small modular (advanced nuclear) reactors. Given the relatively high capital and fixed costs of small modular reactors, plans for their construction represent an expectation of higher future energy prices. This suggests that, in the decades to come, at least in certain areas of the country, affected sources may be able to maintain a place in the dispatch curve that allows them to continue to generate while they continue to operate CCS, even in the absence of additional revenues for CO_2. We discuss these potential developments in the final TSD, *Power Sector Trends,* available in the rulemaking docket.

These developments, which may occur by the 2040s—the expiration of the 12-year period for the IRC 45Q tax credit, the potential development of the CO_2 utilization market, and potential market supports for low-GHG generation—may significantly affect the costs to coal-fired steam EGUs of operating their CCS controls. As a result, the EPA will closely monitor these developments. Our efforts will include consulting with other agencies with expertise and information, including DOE, which currently has a program, the Carbon Conversion Program, in the Office of Carbon Management, that funds research into CO_2 utilization. We regularly consult with stakeholders, including industry stakeholders, and will continue to do so.

In light of these potential significant developments and their impacts, potentially positive or negative, on the economics of continued generation by affected sources that have installed CCS, the EPA is committing to review and, if appropriate, revise this rule by January 1, 2041. This commitment is included in the regulations that the EPA is promulgating with this rule. The EPA will conduct this review based on what we learn from monitoring these developments, as noted above. Completing this review and any appropriate revisions by that date will allow time for the states to revise, if necessary, standards applicable to affected sources, and for the EPA to act on those state revisions, by the early to mid-2040s. That is when the 12-year period for the 45Q tax credit is expected to expire for affected sources that comply with the CCS requirement by January 1, 2032, and when other significant developments noted above may be well underway.

VIII. Requirements for New and Reconstructed Stationary Combustion Turbine EGUs and Rationale for Requirements

A. Overview

This section discusses the requirements for stationary combustion turbine EGUs that commence construction or reconstruction after May 23, 2023. The requirements are codified in 40 CFR part 60, subpart TTTTa. The EPA explains in section VIII.B of this document the two basic turbine technologies that are used in the power sector and are covered by 40 CFR part 60, subpart TTTTa. Those are simple cycle combustion turbines and combined cycle combustion turbines. The EPA also explains how these technologies are used in the three subcategories: low load turbines, intermediate load turbines, and base load turbines. Section VIII.C provides an overview of how stationary combustion turbines have been previously regulated. Section VIII.D discusses the EPA's decision to revisit the standards for new and reconstructed turbines as part of the statutorily required 8-year review of the NSPS. Section VIII.E discusses changes that the EPA is finalizing in both applicability and subcategories in the new 40 CFR part 60, subpart TTTTa, as compared to those codified previously in 40 CFR part 60, subpart TTTT. Most notably, for new and reconstructed natural gas-fired combustion turbines, the EPA is finalizing BSER determinations and standards of performance for the three subcategories mentioned above—low load, intermediate load, and base load.

Sections VIII.F and VIII.G of this document discuss the EPA's

[705] *See* National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 81 FR 63112–01 (September 14, 2016).

determination of the BSER for each of the three subcategories of combustion turbines and the applicable standards of performance, respectively. For low load combustion turbines, the EPA is finalizing a determination that the use of lower-emitting fuels is the appropriate BSER. For intermediate load combustion turbines, the EPA is finalizing a determination that highly efficient simple cycle generation is the appropriate BSER. For base load combustion turbines, the EPA is finalizing a determination that the BSER includes two components that correspond initially to a two-phase standard of performance. The first component of the BSER, with an immediate compliance date (phase 1), is highly efficient generation based on the performance of a highly efficient combined cycle turbine and the second component of the BSER, with a compliance date of January 1, 2032 (phase 2), is based on the use of CCS with a 90 percent capture rate, along with continued use of highly efficient generation. For base load turbines, the standards of performance corresponding to both components of the BSER would apply to all new and reconstructed sources that commence construction or reconstruction after May 23, 2023. The EPA occasionally refers to these standards of performance as the phase 1 or phase 2 standards.

B. Combustion Turbine Technology

For purposes of 40 CFR part 60, subparts TTTT and TTTTa, stationary combustion turbines include both simple cycle and combined cycle EGUs. Simple cycle turbines operate in the Brayton thermodynamic cycle and include three primary components: a multi-stage compressor, a combustion chamber (*i.e.,* combustor), and a turbine. The compressor is used to supply large volumes of high-pressure air to the combustion chamber. The combustion chamber converts fuel to heat and expands the now heated, compressed air through the turbine to create shaft work. The shaft work drives an electric generator to produce electricity. Combustion turbines that recover the energy in the high-temperature exhaust—instead of venting it directly to the atmosphere—are combined cycle EGUs and can obtain additional useful electric output. A combined cycle EGU includes an HRSG operating in the Rankine thermodynamic cycle. The HRSG receives the high-temperature exhaust and converts the heat to mechanical energy by producing steam that is then fed into a steam turbine that, in turn, drives an electric generator. As the thermal efficiency of a stationary combustion turbine EGU is increased, less fuel is burned to produce the same amount of electricity, with a corresponding decrease in fuel costs and lower emissions of CO_2 and, generally, of other air pollutants. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process.

Combustion turbines serve various roles in the power sector. Some combustion turbines operate at low annual capacity factors and are available to provide temporary power during periods of high load demand. These turbines are often referred to as ''peaking units.'' Some combustion turbines operate at intermediate annual capacity factors and are often referred to as cycling or load-following units. Other combustion turbines operate at high annual capacity factors to serve base load demand and are often referred to as base load units. In this rulemaking, the EPA refers to these types of combustion turbines as low load, intermediate load, and base load, respectively.

Low load combustion turbines provide reserve capacity, support grid reliability, and generally provide power during periods of peak electric demand. As such, the units may operate at or near their full capacity, but only for short periods, as needed. Because these units only operate occasionally, capital expenses are a major factor in the overall cost of electricity, and often, the lowest capital cost (and generally less efficient) simple cycle EGUs are intended for use only during periods of peak electric demand. Due to their low efficiency, these units require more fuel per MWh of electricity produced and their operating costs tend to be higher. Because of the higher operating costs, they are generally some of the last units in the dispatch order. Important characteristics for low load combustion turbines include their low capital costs, their ability to start quickly and to rapidly ramp up to full load, and their ability to operate at partial loads while maintaining acceptable emission rates and efficiencies. The ability to start quickly and rapidly attain full load is important to maximize revenue during periods of peak electric prices and to meet sudden shifts in demand. In contrast, under steady-state conditions, more efficient combined cycle EGUs are dispatched ahead of low load turbines and often operate at higher annual capacity factors.

Highly efficient simple cycle turbines and flexible fast-start combined cycle turbines both offer different advantages and disadvantages when operating at intermediate loads. One of the roles of these intermediate or load following EGUs is to provide dispatchable backup power to support variable renewable generating sources (*e.g.,* solar and wind). A developer's decision as to whether to build a simple cycle turbine or a combined cycle turbine to serve intermediate load demand is based on several factors related to the intended operation of the unit. These factors would include how frequently the unit is expected to cycle between starts and stops, the predominant load level at which the unit is expected to operate, and whether this level of operation is expected to remain consistent or is expected to vary over the lifetime of the unit. In areas of the U.S. with vertically integrated electricity markets, utilities determine dispatch orders based generally on economic merit of individual units. Meanwhile, in areas of the U.S. inside organized wholesale electricity markets, owner/operators of individual combustion turbines control whether and how units will operate over time, but they do not necessarily control the precise timing of dispatch for units in any given day or hour. Such short-term dispatch decisions are often made by regional grid operators that determine, on a moment-to-moment basis, which available individual units should operate to balance supply and demand and other requirements in an optimal manner, based on operating costs, price bids, and/or operational characteristics. However, operating permits for simple cycle turbines often contain restrictions on the annual hours of operation that owners/operators incorporate into longer-term operating plans and short-term dispatch decisions.

Intermediate load combustion turbines vary their generation, especially during transition periods between low and high electric demand. Both high-efficiency simple cycle turbines and flexible fast-start combined cycle turbines can fill this cycling role. While the ability to start quickly and quickly ramp up is important, efficiency is also an important characteristic. These combustion turbines generally have higher capital costs than low load combustion turbines but are generally less expensive to operate.

Base load combustion turbines are designed to operate for extended periods at high loads with infrequent starts and stops. Quick-start capability and low capital costs are less important than low operating costs. High-efficiency combined cycle turbines typically fill the role of base load combustion turbines.

The increase in generation from variable renewable energy sources during the past decade has impacted the

way in which dispatchable generating resources operate.[706] For example, the electric output from wind and solar generating sources fluctuates daily and seasonally due to increases and decreases in the wind speed or solar intensity. Due to this variable nature of wind and solar, dispatchable EGUs, including combustion turbines as well as other technologies like energy storage, are used to ensure the reliability of the electric grid. This requires dispatchable power plants to have the ability to quickly start and stop and to rapidly and frequently change load—much more often than was previously needed. These are important characteristics of the combustion turbines that provide firm backup capacity. Combustion turbines are much more flexible than coal-fired utility boilers in this regard and have played an important role during the past decade in ensuring that electric supply and demand are balanced.

As discussed in section IV.F.2 of this preamble, in the final TSD, *Power Sector Trends,* and in the accompanying RIA, the EPA's Power Sector Platform 2023 using IPM projects that natural gas-fired combustion turbines will continue to play an important role in meeting electricity demand. However, that role is projected to evolve as additional renewable and non-renewable low-GHG generation and energy storage technologies are added to the grid. Energy storage technologies can store energy during periods when generation from renewable resources is high relative to demand and can provide electricity to the grid during other periods. Energy storage technologies are projected to reduce the need for base load fossil fuel-fired firm dispatchable power plants, and the capacity factors of combined cycle EGUs are forecast to decline by 2040.

C. Overview of Regulation of Stationary Combustion Turbines for GHGs

As explained earlier in this preamble, the EPA originally regulated new and reconstructed stationary combustion turbine EGUs for emissions of GHGs in 2015 under 40 CFR part 60, subpart TTTT. In 40 CFR part 60, subpart TTTT, the EPA created three subcategories: two for natural gas-fired combustion turbines and one for multi-fuel-fired combustion turbines. For natural gas-fired turbines, the EPA created a subcategory for base load turbines and a separate subcategory for non-base load turbines. Base load turbines were defined as combustion turbines with electric sales greater than a site-specific electric sales threshold based on the design efficiency of the combustion turbine. Non-base load turbines were defined as combustion turbines with a capacity factor less than or equal to the site-specific electric sales threshold. For base load turbines, the EPA set a standard of 1,000 lb CO_2/MWh-gross based on efficient combined cycle turbine technology. For non-base load and multi-fuel-fired turbines, the EPA set a standard based on the use of lower-emitting fuels that varied from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending upon whether the turbine burned primarily natural gas or other lower-emitting fuels.

D. Eight-Year Review of NSPS

CAA section 111(b)(1)(B) requires the Administrator to ''at least every 8 years, review and, if appropriate, revise [the NSPS] . . . .'' The provision further provides that ''the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such [NSPS].''

The EPA promulgated the NSPS for GHG emissions for stationary combustion turbines in 2015. Announcements and modeling projections show that project developers are building new fossil fuel-fired combustion turbines and have plans to continue building additional capacity. Because the emissions from this added capacity have the potential to be large and these units are likely to have long operating lives (25 years or more), it is important to limit emissions from these new units. Accordingly, in this final rule, the EPA is updating the NSPS for newly constructed and reconstructed fossil fuel-fired stationary combustion turbines.

E. Applicability Requirements and Subcategorization

This section describes the amendments to the specific applicability criteria for non-fossil fuel-fired EGUs, industrial EGUs, CHP EGUs, and combustion turbine EGUs not connected to a natural gas pipeline. The EPA is also making certain changes to the applicability requirements for stationary combustion turbines affected by this final rule as compared to those for sources affected by the 2015 NSPS. The amendments are described below and include the elimination of the multi-fuel-fired subcategory, further binning non-base load combustion turbines into low load and intermediate load subcategories and establishing a capacity factor threshold for base load combustion turbines.

1. Applicability Requirements

In general, the EPA refers to fossil fuel-fired EGUs that would be subject to a CAA section 111 NSPS as ''affected'' EGUs or units. An EGU is any fossil fuel-fired electric utility steam generating unit (*i.e.,* a utility boiler or IGCC unit) or stationary combustion turbine (in either simple cycle or combined cycle configuration). To be considered an affected EGU under the 2015 NSPS at 40 CFR part 60, subpart TTTT, the unit must meet the following applicability criteria: The unit must: (1) be capable of combusting more than 250 MMBtu/h (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.,* for sale to the grid).[707] However, 40 CFR part 60, subpart TTTT, includes applicability exemptions for certain EGUs, including: (1) non-fossil fuel-fired units subject to a federally enforceable permit that limits the use of fossil fuels to 10 percent or less of their heat input capacity on an annual basis; (2) CHP units that are subject to a federally enforceable permit limiting annual net electric sales to no more than either the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh, whichever is greater; (3) stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.,* those that are not connected to a natural gas pipeline); (4) utility boilers and IGCC units that have always been subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less; (5) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (6) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (7) certain projects under development, as discussed in the preamble for the 2015 final NSPS.

[706] Dispatchable generating sources are those that can be turned on and off and adjusted to provide power to the electric grid based on the demand for electricity. Variable (sometimes referred to as intermittent) generating sources are those that supply electricity based on external factors that are not controlled by the owner/operator of the source (*e.g.,* wind and solar sources).

[707] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the ''base load rating criterion.'' Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

a. Revisions to 40 CFR Part 60, Subpart TTTT

The EPA is amending 40 CFR 60.5508 and 60.5509 to reflect that stationary combustion turbines that commenced construction after January 8, 2014, or reconstruction after June 18, 2014, and before May 24, 2023, and that meet the relevant applicability criteria are subject to 40 CFR part 60, subpart TTTT. For steam generating EGUs and IGCC units, 40 CFR part 60, subpart TTTT, remains applicable for units constructed after January 8, 2014, or reconstructed after June 18, 2014. The EPA is finalizing 40 CFR part 60, subpart TTTTa, to be applicable to stationary combustion turbines that commence construction or reconstruction after May 23, 2023, and that meet the relevant applicability criteria.

b. Revisions to 40 CFR Part 60, Subpart TTTT, That Are Also Included in 40 CFR Part 60, Subpart TTTTa

The EPA is finalizing that 40 CFR part 60, subpart TTTT, and 40 CFR part 60, subpart TTTTa, use similar regulatory text except where specifically stated. This section describes amendments included in both subparts.

i. Applicability to Non-Fossil Fuel-Fired EGUs

The current non-fossil applicability exemption in 40 CFR part 60, subpart TTTT, is based strictly on the combustion of non-fossil fuels (*e.g.,* biomass). To be considered a non-fossil fuel-fired EGU, the EGU must be both: (1) Capable of combusting more than 50 percent non-fossil fuel and (2) subject to a federally enforceable permit condition limiting the annual heat input capacity for all fossil fuels combined of 10 percent or less. The current language does not take heat input from non-combustion sources (*e.g.,* solar thermal) into account. Certain solar thermal installations have natural gas backup burners larger than 250 MMBtu/h. As currently treated in 40 CFR part 60, subpart TTTT, these solar thermal installations are not eligible to be considered non-fossil units because they are not capable of deriving more than 50 percent of their heat input from the combustion of non-fossil fuels. Therefore, solar thermal installations that include backup burners could meet the applicability criteria of 40 CFR part 60, subpart TTTT, even if the burners are limited to an annual capacity factor of 10 percent or less. These EGUs would readily comply with the standard of performance, but the reporting and recordkeeping would increase costs for these EGUs.

The EPA proposed and is finalizing several amendments to align the applicability criteria with the original intent to cover only fossil fuel-fired EGUs. These amendments ensure that solar thermal EGUs with natural gas backup burners, like other types of non-fossil fuel-fired units that derive most of their energy from non-fossil fuel sources, are not subject to the requirements of 40 CFR part 60, subpart TTTT or TTTTa. Amending the applicability language to include heat input derived from non-combustion sources allows these facilities to avoid the requirements of 40 CFR part 60, subpart TTTT or TTTTa, by limiting the use of the natural gas burners to less than 10 percent of the capacity factor of the backup burners. Specifically, the EPA is amending the definition of non-fossil fuel-fired EGUs from EGUs capable of ''combusting 50 percent or more non-fossil fuel'' to EGUs capable of ''*deriving* 50 percent or more *of the heat input from* non-fossil fuel *at the base load rating*'' (emphasis added). The definition of base load rating is also being amended to include the heat input from non-combustion sources (*e.g.,* solar thermal).

Revising ''combusting'' to ''deriving'' in the amended non-fossil fuel applicability language ensures that 40 CFR part 60, subparts TTTT and TTTTa, cover the fossil fuel-fired EGUs that the original rule was intended to cover, while minimizing unnecessary costs to EGUs fueled primarily by steam generated without combustion (*e.g.,* thermal energy supplied through the use of solar thermal collectors). The corresponding change in the base load rating to include the heat input from non-combustion sources is necessary to determine the relative heat input from fossil fuel and non-fossil fuel sources.

ii. Industrial EGUs

(A) Applicability to Industrial EGUs

In simple terms, the current applicability provisions in 40 CFR part 60, subpart TTTT, require that an EGU be capable of combusting more than 250 MMBtu/h of fossil fuel and be capable of selling 25 MW to a utility distribution system to be subject to 40 CFR part 60, subpart TTTT. These applicability provisions exclude industrial EGUs. However, the definition of an EGU also includes ''integrated equipment that provides electricity or useful thermal output.'' This language facilitates the integration of non-emitting generation and avoids energy inputs from non-affected facilities being used in the emission calculation without also considering the emissions of those facilities (*e.g.,* an auxiliary boiler providing steam to a primary boiler). This language could result in certain large processes being included as part of the EGU and meeting the applicability criteria. For example, the high-temperature exhaust from an industrial process (*e.g.,* calcining kilns, dryer, metals processing, or carbon black production facilities) that consumes fossil fuel could be sent to a HRSG to produce electricity. If the industrial process uses more than 250 MMBtu/h heat input and the electric sales exceed the applicability criteria, then the unit could be subject to 40 CFR part 60, subpart TTTT or TTTTa. This is potentially problematic for multiple reasons. First, it is difficult to determine the useful output of the EGU (*i.e.,* HRSG) since part of the useful output is included in the industrial process. In addition, the fossil fuel that is combusted could have a relatively high CO_2 emissions rate on a lb/MMBtu basis, making it potentially problematic to meet the standard of performance using efficient generation. This could result in the owner/operator reducing the electric output of the industrial facility to avoid the applicability criteria. Finally, the compliance costs associated with 40 CFR part 60, subpart TTTT or TTTTa, could discourage the development of environmentally beneficial projects.

To avoid these outcomes, the EPA is, as proposed, amending the applicability provision that exempts EGUs where greater than 50 percent of the heat input is derived from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.[708] Reducing the output or not developing industrial electric generating projects where the majority of the heat input is derived from the industrial process itself would not necessarily result in reductions in GHG emissions from the industrial facility. However, the electricity that would have been produced from the industrial project could still be needed. Therefore, projects of this type provide significant environmental benefit by providing additional useful output with little if any additional environmental impact. Including these types of projects would result in regulatory burden without any associated environmental benefit and could discourage project development,

[708] Auxiliary equipment such as boilers or combustion turbines that provide heat or electricity to the primary EGU (including to any control equipment) would still be considered integrated equipment and included as part of the affected facility.

leading to potential overall increases in GHG emissions.

(B) Industrial EGUs Electric Sales Threshold Permit Requirement

The current electric sales applicability exemption in 40 CFR part 60, subpart TTTT, for non-CHP steam generating units includes the provision that EGUs have ''*always been subject to a federally enforceable permit* limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less'' (emphasis added). The justification for this restriction includes that the 40 CFR part 60, subpart Da, applicability language includes ''constructed for the purpose of . . .'' and the Agency concluded that the intent was defined by permit conditions (80 FR 64544; October 23, 2015). This applicability criterion is important both for determining applicability with the new source CAA section 111(b) requirements and for determining whether existing steam generating units are subject to the existing source CAA section 111(d) requirements. For steam generating units that commenced construction after September 18, 1978, the applicability of 40 CFR part 60, subpart Da, would be relatively clear as to what criteria pollutant NSPS is applicable to the facility. However, for steam generating units that commenced construction prior to September 18, 1978, or where the owner/operator determined that criteria pollutant NSPS applicability was not critical to the project (*e.g.,* emission controls were sufficient to comply with either the EGU or industrial boiler criteria pollutant NSPS), owners/operators might not have requested that an electric sales permit restriction be included in the operating permit. Under the current applicability language, some onsite EGUs could be covered by the existing source CAA section 111(d) requirements even if they have never sold electricity to the grid. To avoid covering these industrial EGUs, the EPA proposed and is finalizing amendments to the electric sales exemption in 40 CFR part 60, subparts TTTT and TTTTa, to read, ''annual net electric sales *have never exceeded one-third of its potential electric output or 219,000 MWh, whichever is greater, and is* [the ''*always been*'' would be deleted] subject to a federally enforceable permit limiting annual net electric sales to one-third or less of their potential electric output (*e.g.,* limiting hours of operation to less than 2,920 hours annually) or limiting annual electric sales to 219,000 MWh or less'' (emphasis added). EGUs that reduce current generation will continue to be covered as long as they sold more than one-third of their potential electric output at some time in the past. The revisions make it possible for an owner/operator of an existing industrial EGU to provide evidence to the Administrator that the facility has never sold electricity in excess of the electricity sales threshold and to modify their permit to limit sales in the future. Without the amendment, owners/operators of any non-CHP industrial EGU capable of selling 25 MW would be subject to the existing source CAA section 111(d) requirements even if they have never sold any electricity. Therefore, the EPA is eliminating the requirement that existing industrial EGUs must have always been subject to a permit restriction limiting net electric sales.

iii. Determination of the Design Efficiency

The design efficiency (*i.e.,* the efficiency of converting thermal energy to useful energy output) of a combustion turbine is used to determine the electric sales applicability threshold. In 40 CFR part 60, subpart TTTT, the sales criteria are based in part on the individual EGU design efficiency. Three methods for determining the design efficiency are currently provided in 40 CFR part 60, subpart TTTT.[709] Since the 2015 NSPS was finalized, the EPA has become aware that owners/operators of certain existing EGUs do not have records of the original design efficiency. These units would not be able to readily determine whether they meet the applicability criteria (and would therefore be subject to CAA section 111(d) requirements for existing sources) in the same way that 111(b) sources would be able to determine if the facility meets the applicability criteria. Many of these EGUs are CHP units that are unlikely to meet the 111(b) applicability criteria and would therefore not be subject to any future 111(d) requirements. However, the language in the 2015 NSPS would require them to conduct additional testing to demonstrate this. The requirement would result in burden to the regulated community without any environmental benefit. The electricity generating market has changed, in some cases dramatically, during the lifetime of existing EGUs, especially concerning ownership. As a result of acquisitions and mergers, original EGU design efficiency documentation, as well as performance guarantee results that affirmed the design efficiency, may no longer exist. Moreover, such documentation and results may not be relevant for current EGU efficiencies, as changes to original EGU configurations, upon which the original design efficiencies were based, render those original design efficiencies moot, meaning that there would be little reason to maintain former design efficiency documentation since it would not comport with the efficiency associated with current EGU configurations. As the three specified methods would rely on documentation from the original EGU configuration performance guarantee testing, and results from that documentation may no longer exist or be relevant, it is appropriate to allow other means to demonstrate EGU design efficiency. To reduce potential future compliance burden, the EPA proposed and is finalizing in 40 CFR part 60, subparts TTTT and TTTTa, to allow alternative methods as approved by the Administrator on a case-by-case basis. Owners/operators of EGUs can petition the Administrator in writing to use an alternate method to determine the design efficiency. The Administrator's discretion is intentionally left broad and can extend to other American Society of Mechanical Engineers (ASME) or International Organization for Standardization (ISO) methods as well as to operating data to demonstrate the design efficiency of the EGU. The EPA also proposed and is finalizing a change to the applicability of paragraph 60.8(b) in table 3 of 40 CFR part 60, subpart TTTT, from ''no'' to ''yes'' and that the applicability of paragraph 60.8(b) in table 3 of 40 CFR part 60, subpart TTTTa, is ''yes.'' This allows the Administrator to approve alternatives to the test methods specified in 40 CFR part 60, subparts TTTT and TTTTa.

c. Applicability for 40 CFR Part 60, Subpart TTTTa

This section describes applicability criteria that are only incorporated into 40 CFR part 60, subpart TTTTa, and that differ from the requirements in 40 CFR part 60, subpart TTTT.

Section 111 of the CAA defines a new or modified source for purposes of a given NSPS as any stationary source that commences construction or modification after the publication of the proposed regulation. Thus, the standards of performance apply to EGUs that commence construction or reconstruction after the date of proposal of this rule—May 23, 2023. EGUs that commenced construction after the date

[709] 40 CFR part 60, subpart TTTT, currently lists ''ASME PTC 22 Gas Turbines,'' ''ASME PTC 46 Overall Plant Performance,'' and ''ISO 2314 Gas turbines—acceptance tests'' as approved methods to determine the design efficiency.

of the proposal for the 2015 NSPS and by May 23, 2023, will remain subject to the standards of performance promulgated in the 2015 NSPS. A modification is any physical change in, or change in the method of operation of, an existing source that increases the amount of any air pollutant emitted to which a standard applies.[710] The NSPS general provisions (40 CFR part 60, subpart A) provide that an existing source is considered a new source if it undertakes a reconstruction.[711]

The EPA is finalizing the same applicability requirements in 40 CFR part 60, subpart TTTTa, as the applicability requirements in 40 CFR part 60, subpart TTTT. The stationary combustion turbine must meet the following applicability criteria: The stationary combustion turbine must: (1) be capable of combusting more than 250 MMBtu/h (260 gigajoules per hour (GJ/h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (*i.e.,* for sale to the grid).[712] In addition, the EPA proposed and is finalizing in 40 CFR part 60, subpart TTTTa, to include applicability exemptions for stationary combustion turbines that are: (1) capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less; (2) combined heat and power units subject to a federally enforceable permit condition limiting annual net electric sales to no more than 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater; (3) serving a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity is 25 MW or less; (4) municipal waste combustors that are subject to 40 CFR part 60, subpart Eb; (5) commercial or industrial solid waste incineration units subject to 40 CFR part 60, subpart CCCC; and (6) deriving greater than 50 percent of heat input from an industrial process that does not produce any electrical or mechanical output that is used outside the affected stationary combustion turbine.

The EPA proposed the same requirements to combustion turbines in non-continental areas (*i.e.,* Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) and non-contiguous areas (non-continental areas and Alaska) as the EPA did for comparable units in the contiguous 48 states.[713] However, the Agency solicited comment on whether owners/operators of new and reconstructed combustion turbines in non-continental and non-contiguous areas should be subject to different requirements. Commenters generally commented that due to the difference in non-contiguous areas relative to the lower 48 states, the proposed requirements should not apply to owners/operators of new or reconstructed combustion turbines in non-contiguous areas. The Agency has considered these comments and is finalizing that only the initial BSER component will be applicable to owners/operators of combustion turbines located in non-contiguous areas. Therefore, owners/operators of base load combustions turbines would not be subject to the CCS-based numerical standards in 2032 and would continue to comply with the efficiency-based numeric standard. Based on information reported in the 2022 EIA Form EIA–860, there are no planned new combustion turbines in either Alaska or Hawaii. In addition, since 2015 no new combustion turbines have commenced operation in Hawaii. Two new combustion turbine facilities totaling 190 MW have commenced operation in Alaska since 2015. One facility is a combined cycle CHP facility and the other is at an industrial facility and neither facility would likely meet the applicability of 40 CFR part 60, subpart TTTTa. Therefore, not finalizing phase-2 BSER for non-continental and non-contiguous areas will have limited, if any, impacts on emissions or costs. The EPA notes that the Agency has the authority to amend this decision in future rulemakings.

i. Applicability to CHP Units

For 40 CFR part 60, subpart TTTT, owners/operators of CHP units calculate net electric sales and net energy output using an approach that includes ''at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output.'' It is unlikely that a CHP unit with a relatively low electric output (*i.e.,* less than 20.0 percent) would meet the applicability criteria. However, if a CHP unit with less than 20.0 percent of the total output consisting of electricity were to meet the applicability criteria, the net electric sales and net energy output would be calculated the same as for a traditional non-CHP EGU. Even so, it is not clear that these CHP units would have less environmental benefit per unit of electricity produced than would more traditional CHP units. For 40 CFR part 60, subpart TTTTa, the EPA proposed and is finalizing to eliminate the restriction that CHP units produce at least 20.0 percent electrical or mechanical output to qualify for the CHP-specific method for calculating net electric sales and net energy output.

In the 2015 NSPS, the EPA did not issue standards of performance for certain types of sources—including industrial CHP units and CHPs that are subject to a federally enforceable permit limiting annual net electric sales to no more than the unit's design efficiency multiplied by its potential electric output, or 219,000 MWh or less, whichever is greater. For CHP units, the approach in 40 CFR part 60, subpart TTTT, for determining net electric sales for applicability purposes allows the owner/operator to subtract the purchased power of the thermal host facility. The intent of the approach is to determine applicability similarly for third-party developers and CHP units owned by the thermal host facility.[714] However, as written in 40 CFR part 60, subpart TTTT, each third-party CHP unit would subtract the entire electricity use of the thermal host facility when determining its net electric sales. It is clearly not the intent of the provision to allow multiple third-party developers that serve the same thermal host to all subtract the purchased power of the thermal host facility when determining net electric sales. This would result in counting the purchased power multiple times. In addition, it is not the intent of the provision to allow a CHP developer to provide a trivial amount of useful thermal output to multiple thermal hosts and then subtract all the thermal hosts' purchased power when determining net electric sales for applicability purposes. The EPA

[710] 40 CFR 60.2.

[711] 40 CFR 60.15(a).

[712] The EPA refers to the capability to combust 250 MMBtu/h of fossil fuel as the ''base load rating criterion.'' Note that 250 MMBtu/h is equivalent to 73 MW or 260 GJ/h heat input.

[713] 40 CFR part 60, subpart TTTT, also includes coverage for owners/operators of combustion turbines in non-contiguous areas. However, owners/operators of combustion turbines not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline) are not subject to the rule. This exemption covers many combustion turbines in non-contiguous areas.

[714] For contractual reasons, many developers of CHP units sell the majority of the generated electricity to the electricity distribution grid. Owners/operators of both the CHP unit and thermal host can subtract the site purchased power when determining net electric sales. Third-party developers that do not own the thermal host can also subtract the purchased power of the thermal host when determining net electric sales for applicability purposes.

proposed and is finalizing in 40 CFR part 60, subpart TTTTa, to limit to the amount of thermal host purchased power that a third-party CHP developer can subtract for electric sales when determining net electric sales equivalent to the percentage of useful thermal output provided to the host facility by the specific CHP unit. This approach eliminates both circumvention of the intended applicability by sales of trivial amounts of useful thermal output and double counting of thermal host-purchased power.

Finally, to avoid potential double counting of electric sales, the EPA proposed and is finalizing that for CHP units determining net electric sales, purchased power of the host facility be determined based on the percentage of thermal power provided to the host facility by the specific CHP facility.

ii. Non-Natural Gas Stationary Combustion Turbines

There is currently an exemption in 40 CFR part 60, subpart TTTT, for stationary combustion turbines that are not physically capable of combusting natural gas (*e.g.,* those that are not connected to a natural gas pipeline). While combustion turbines not connected to a natural gas pipeline meet the general applicability of 40 CFR part 60, subpart TTTT, these units are not subject to any of the requirements. The EPA is not including in 40 CFR part 60, subpart TTTTa, the exemption for stationary combustion turbines that are not physically capable of combusting natural gas. As described in the standards of performance section, owners/operators of combustion turbines burning fuels with a higher heat input emission rate than natural gas would adjust the natural gas-fired emissions rate by the ratio of the heat input-based emission rates. The overall result is that new stationary combustion turbines combusting fuels with higher GHG emissions rates than natural gas on a lb CO_2/MMBtu basis must maintain the same efficiency compared to a natural gas-fired combustion turbine and comply with a standard of performance based on the identified BSER.

2. Subcategorization

In this final rule, the EPA is continuing to include both simple and combined cycle turbines in the definition of a stationary combustion turbine, and like in prior rules for this source category, the Agency is finalizing three subcategories—low load, intermediate load, and base load combustion turbines. These subcategories are determined based on electric sales (*i.e.,* utilization) relative to the combustion turbines' potential electric output to an electric distribution network on both a 12-operating month and 3-year rolling average basis. The applicable subcategory is determined each operating month and a stationary combustion turbine can switch subcategories if the owner/operator changes the way the facility is operated. Subcategorization based on percent electric sales is a proxy for how a combustion turbine operates and for determining the BSER and corresponding emission standards. For example, low load combustion turbines tend to spend a relatively high percentage of operating hours starting and stopping. However, within each subcategory not all combustion turbines operate the same. Some low load combustion turbines operate with less starting and stopping, but in general, combustion turbines tend to operate with fewer starts and stops (*i.e.,* more steady-state hours of operation) with increasing percentages of electric sales. The BSER for each subcategory is based on representative operation of the combustion turbines in that subcategory and on what is achievable for the subcategory as a whole.

Subcategorization by electric sales is similar, but not identical, to subcategorizing by heat input-based capacity factors or annual hours of operation limits.[715] The EPA has determined that, for NSPS purposes, electric sales is appropriate because it reflects operational limitations inherent in the design of certain units, and also that—given these differences—certain emission reduction technologies are more suitable for some units than for others.[716] This subcategorization approach is also consistent with industry practice. For example, operating permits for simple cycle turbines often include annual operating hour limitations of 1,500 to 4,000 hours annually. When average hourly capacity factors (*i.e.,* duty cycles) are accounted for, these hourly restrictions are similar to annual capacity factor restrictions of approximately 15 percent and 40 percent, respectively. The owners or operators of these combustion turbines never intend for them to provide base load power. In contrast, operating permits do not typically restrict the number of hours of annual operation for combined cycle turbines, reflecting that these types of combustion turbines are intended to have the ability to provide base load power.

The EPA evaluated the operation of the three general combustion turbine technologies—combined cycle turbines, frame-type simple cycle turbines, and aeroderivative simple cycle turbines—when determining the subcategorization approach in this rulemaking.[717] The EPA found that, at the same capacity factor, aeroderivative simple cycle turbines have more starts (including fewer operating hours per start) than either frame simple cycle turbines or combined cycle turbines. The maximum number of starts for aeroderivative simple cycle turbines occurs at capacity factors of approximately 30 percent and the maximum number of starts for frame simple cycle turbines and combined cycle turbines both occur at capacity factors of approximately 25 percent. In terms of the median hours of operation per start, the hours per starts increases exponentially with capacity factor for each type of combustion turbine. The rate of increase is greatest for combined cycle turbines with the run times per start increasing significantly at capacity factors of 40 and greater. This threshold roughly matches the subcategorization threshold for intermediate load and base load turbines in this final rule. As is discussed later in section VIII.F.3 and VIII.F.4, technology options including those related to efficiency and to post combustion capture are impacted by the way units operate and can be more effective for units with fewer stops and starts.

a. Legal Basis for Subcategorization

As noted in section V.C.1 of this preamble, CAA section 111(b)(2) provides that the EPA ''may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing . . . standards [of performance].'' The D.C. Circuit has held that the EPA has broad discretion in determining whether and how to subcategorize under CAA section 111(b)(2). *Lignite Energy Council,* 198 F.3d at 933. As also noted in section V.C.1 of this preamble, in prior CAA section 111 rules, the EPA has subcategorized on numerous bases, including, among other things, fuel type and load, *i.e.,* utilization. In particular, as noted in section V.C.1 of this preamble, the EPA subcategorized on the basis of utilization—for base load

[715] Percent electric sales thresholds, capacity factor thresholds, and annual hours of operation limitations all categorize combustion turbines based on utilization.

[716] While utilization and electric sales are often similar, the EPA uses electric sales because the focus of the applicability is facilities that sell electricity to the grid and not industrial facilities where the electricity is generated primarily for use onsite.

[717] The EPA used manufacturers' designations for frame and aeroderivative combustion turbines.

and non-base load subcategories—in the 2015 NSPS for GHG emissions from combustion turbines, *Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units,* 80 FR 64509 (October 23, 2015), and also in the *NESHAP for Reciprocating Internal Combustion Engines; NSPS for Stationary Internal Combustion Engines,* 79 FR 48072–01 (August 15, 2014).

Subcategorizing combustion turbines based on utilization is appropriate because it recognizes the way differently designed combustion turbines actually operate. Project developers do not construct combined cycle combustion turbine system to start and stop often to serve peak demand. Similarly, project developers do not construct and install simple cycle combustion turbines to operate at higher capacity factors to provide base load demand. And intermediate load demand may be served by higher efficiency simple cycle turbine systems or by ''quick start'' combined cycle units. Thus, there are distinguishing features (*i.e.,* different classes, types, and sizes) of turbines that are predominantly used in each of the utilization-based subcategories. Further, the amount of utilization and the mode of operation are relevant for the systems of emission reduction that the EPA may evaluate to be the BSER and therefore for the resulting standards of performance. See section VII.C.2.a.i for more discussion of the legal basis to subcategorize based upon characteristics relevant to the controls the EPA may determine to be the BSER.

As noted in sections VIII.E.2.b and VIII.F of this preamble, combustion turbines that operate at low load have highly variable operation and therefore highly variable emission rates. This variability made it challenging for the EPA to specify a BSER based on efficient design and operation and limits the BSER for purposes of this rulemaking to lower-emitting fuels. The EPA notes that the subcategorization threshold and the standard of performance are related. For example, the Agency could have finalized a lower electric sales threshold for the low load subcategory (*e.g.,* 15 percent) and evaluated the emission rates at the lower capacity factors. In future rulemaking the Agency could further evaluate the costs and emissions impacts of reducing the threshold for combustion turbines subject to a BSER based on the use of lower emitting fuels.

Intermediate load combustion turbines (*i.e.,* those that operate at loads that are somewhat higher than the low load peaking units) are most often designed to be simple cycle units rather than combined cycle units. This is because combustion turbines operating in the intermediate load range also start and stop and vary their load frequently (though not as often as low load peaking units). Because of the more frequent starts and stops, simple cycle combustion turbines are more economical for project developers when compared to combined cycle combustion turbines. Utilization of CCS technology is not practicable for those simple cycle units due to the lack of a HRSG. Therefore, the EPA has determined that efficient design and operation is the BSER for intermediate load combustion turbines.

While use of CCS is practicable for combined cycle combustion turbines, it is most appropriate for those units that operate at relatively higher loads (*i.e.,* as base load units) that do not frequently start, stop, and change load. Moreover, with current technology, CCS works better on units running at base load levels.

b. Electric Sales Subcategorization (Low, Intermediate, and Base Load Combustion Turbines)

As noted earlier, in the 2015 NSPS, the EPA established separate standards of performance for new and reconstructed natural gas-fired base load and non-base load stationary combustion turbines. The electric sales threshold distinguishing the two subcategories is based on the design efficiency of individual combustion turbines. A combustion turbine qualifies as a non-base load turbine—and is thus subject to a less stringent standard of performance—if it has net electric sales equal to or less than the design efficiency of the turbine (not to exceed 50 percent) multiplied by the potential electric output (80 FR 64601; October 23, 2015). If the net electric sales exceed that level on both a 12-operating month and 3-calendar year basis, then the combustion turbine is in the base load subcategory and is subject to a more stringent standard of performance. Subcategory applicability can change on a month-to-month basis since applicability is determined each operating month. For additional discussion on this approach, see the 2015 NSPS (80 FR 64609–12; October 23, 2015). The 2015 NSPS non-base load subcategory is broad and includes combustion turbines that assure grid reliability by providing electricity during periods of peak electric demand. These peaking turbines tend to have low annual capacity factors and sell a small amount of their potential electric output. The non-base load subcategory in the 2015 NSPS also includes combustion turbines that operate at intermediate annual capacity factors and are not considered base load EGUs. These intermediate load EGUs provide a variety of services, including providing dispatchable power to support variable generation from renewable sources of electricity. The need for this service has been expanding as the amount of electricity from wind and solar continues to grow. In the 2015 NSPS, the EPA determined the BSER for the non-base load subcategory to be the use of lower-emitting fuels (*e.g.,* natural gas and Nos. 1 and 2 fuel oils). In 2015, the EPA explained that efficient generation did not qualify as the BSER due in part to the challenge of determining an achievable output-based CO_2 emissions rate for all combustion turbines in this subcategory.

In this action, the EPA proposed and is finalizing the subcategories in 40 CFR part 60, subpart TTTTa, that will be applicable to sources that commence construction or reconstruction after May 23, 2023. First, the Agency proposed and is finalizing the definition of design efficiency so that the heat input calculation of an EGU is based on the higher heating value (HHV) of the fuel instead of the lower heating value (LHV), as explained immediately below. This has the effect of lowering the calculated potential electric output and the electric sales threshold. In addition, the EPA proposed and is finalizing division of the non-base load subcategory into separate intermediate and low load subcategories.

i. Higher Heating Value as the Basis for Calculation of the Design Efficiency

The *heat rate* is the amount of energy used by an EGU to generate 1 kWh of electricity and is often provided in units of Btu/kWh. As the thermal efficiency of a combustion turbine EGU is increased, less fuel is burned per kWh generated and there is a corresponding decrease in emissions of CO_2 and other air pollutants. The electric energy output as a fraction of the fuel energy input expressed as a percentage is a common practice for reporting the unit's efficiency. The greater the output of electric energy for a given amount of fuel energy input, the higher the efficiency of the electric generation process. Lower heat rates are associated with more efficient power generating plants.

Efficiency can be calculated using the HHV or the LHV of the fuel. The HHV is the heating value directly determined by calorimetric measurement of the fuel in the laboratory. The LHV is calculated using a formula to account for the

moisture in the combustion gas (*i.e.,* subtracting the energy required to vaporize the water in the flue gas) and is a lower value than the HHV. Consequently, the HHV efficiency for a given EGU is always lower than the corresponding LHV efficiency because the reported heat input for the HHV is larger. For U.S. pipeline natural gas, the HHV heating value is approximately 10 percent higher than the corresponding LHV heating value and varies slightly based on the actual constituent composition of the natural gas.[718] The EPA default is to reference all technologies on a HHV basis,[719] and the Agency is basing the heat input calculation of an EGU on HHV for purposes of the definition of design efficiency. However, it should be recognized that manufacturers of combustion turbines typically use the LHV to express the efficiency of combustion turbines.[720]

Similarly, the electric energy output for an EGU can be expressed as either of two measured values. One value relates to the amount of total electric power generated by the EGU, or *gross* output. However, a portion of this electricity must be used by the EGU facility to operate the unit, including compressors, pumps, fans, electric motors, and pollution control equipment. This within-facility electrical demand, often referred to as the parasitic load or auxiliary load, reduces the amount of power that can be delivered to the transmission grid for distribution and sale to customers. Consequently, electric energy output may also be expressed in terms of *net* output, which reflects the EGU gross output minus its parasitic load.[721]

When using efficiency to compare the effectiveness of different combustion turbine EGU configurations and the applicable GHG emissions control technologies, it is important to ensure that all efficiencies are calculated using the same type of heating value (*i.e.,* HHV or LHV) and the same basis of electric energy output (*i.e.,* MWh-gross or MWh-net). Most emissions data are available on a gross output basis and the EPA is finalizing output-based standards based on gross output. However, to recognize the superior environmental benefit of minimizing auxiliary/parasitic loads, the Agency is including optional equivalent standards on a net output basis. To convert from gross to net output-based standards, the EPA used a 2 percent auxiliary load for simple and combined cycle turbines and a 7 percent auxiliary load for combined cycle EGUs using 90 percent CCS.[722]

ii. Lowering the Threshold Between the Base Load and Non-Base Load Subcategories

The subpart TTTT distinction between a base load and non-base load combustion turbine is determined by the unit's actual electric sales relative to its potential electric sales, assuming the EGU is operated continuously (*i.e.,* percent electric sales). Specifically, stationary combustion turbines are categorized as non-base load and are subsequently subject to a less stringent standard of performance if they have net electric sales equal to or less than their design efficiency (not to exceed 50 percent) multiplied by their potential electric output (80 FR 64601; October 23, 2015). Because the electric sales threshold is based in part on the design efficiency of the EGU, more efficient combustion turbine EGUs can sell a higher percentage of their potential electric output while remaining in the non-base load subcategory. This approach recognizes both the environmental benefit of combustion turbines with higher design efficiencies and provides flexibility to the regulated community. In the 2015 NSPS, it was unclear how often high-efficiency simple cycle EGUs would be called upon to support increased generation from variable renewable generating resources. Therefore, the Agency determined it was appropriate to provide maximum flexibility to the regulated community. To do this, the Agency based the numeric value of the design efficiency, which is used to calculate the electric sales threshold, on the LHV efficiency. This had the impact of allowing combustion turbines to sell a greater share of their potential electric output while remaining in the non-base load subcategory.

The EPA proposed and is finalizing that the design efficiency in 40 CFR part 60, subpart TTTTa be based on the HHV efficiency instead of LHV efficiency and to not include the 50 percent maximum and 33 percent minimum restrictions. When determining the potential electric output used in calculating the electric sales threshold in 40 CFR part 60, subpart TTTT, design efficiencies of greater than 50 percent are reduced to 50 percent and design efficiencies of less than 33 percent are increased to 33 percent for determining electric sales threshold subcategorization criteria. The 50 percent criterion was established to limit non-base load EGUs from selling greater than 55 percent of their potential electric sales.[723] The 33 percent criterion was included to be consistent with applicability thresholds in the electric utility criteria pollutant NSPS (40 CFR part 60, subpart Da).

Neither of those criteria are appropriate for 40 CFR part 60, subpart TTTTa, and the EPA proposed and is finalizing a decision that they are not incorporated when determining the electric sales threshold. Instead, as discussed later in the section, the EPA is finalizing a fixed percent electric sales thresholds and the design efficiency does not impact the subcategorization thresholds. However, the design efficiency is still used when determining the potential electric sales and any restriction on using the actual design efficiency of the combustion turbine would have the impact of changing the threshold. If this restriction were maintained, it would reduce the regulatory incentive for manufacturers to invest in programs to develop higher efficiency combustion turbines.

The EPA also proposed and is finalizing a decision to eliminate the 33 percent minimum design efficiency in the calculation of the potential electric output. The EPA is unaware of any new combustion turbines with design efficiencies meeting the general

[718] The HHV of natural gas is 1.108 times the LHV of natural gas. Therefore, the HHV efficiency is equal to the LHV efficiency divided by 1.108. For example, an EGU with a LHV efficiency of 59.4 percent is equal to a HHV efficiency of 53.6 percent. The HHV/LHV ratio is dependent on the composition of the natural gas (*i.e.,* the percentage of each chemical species (*e.g.,* methane, ethane, propane)) within the pipeline and will slightly move the ratio.

[719] Natural gas is also sold on a HHV basis.

[720] European plants tend to report thermal efficiency based on the LHV of the fuel rather than the HHV for both combustion turbines and steam generating EGUs. In the U.S., boiler efficiency is typically reported on a HHV basis.

[721] It is important to note that net output values reflect the net output delivered to the electric grid and not the net output delivered to the end user. Electricity is lost as it is transmitted from the point of generation to the end user and these ''line losses'' increase the farther the power is transmitted. 40 CFR part 60, subpart TTTT, provides a way to account for the environmental benefit of reduced line losses by crediting CHP EGUs, which are typically located close to large electric load centers. See 40 CFR 60.5540(a)(5)(i) and the definitions of gross energy output and net energy output in 40 CFR 60.5580.

[722] The 7 percent auxiliary load for combined cycle turbines with 90 percent CCS is specific to electric output. Additional auxiliary load includes thermal energy that is diverted to the CCS system instead of being used to generate additional electricity. This additional auxiliary thermal energy is accounted for when converting the phase 1 emissions standard to the phase 2 standard.

[723] While the design efficiency is capped at 50 percent on a LHV basis, the base load rating (maximum heat input of the combustion turbine) is on a HHV basis. This mixture of LHV and HHV results in the electric sales threshold being 11 percent higher than the design efficiency. The design efficiency of all new combined cycle EGUs exceed 50 percent on a LHV basis.

applicability criteria of less than 33 percent; and this will likely have no cost or emissions impact.

The EPA solicited comment on whether the intermediate/base load electric sales threshold should be reduced further to a range that would lower the base load electric sales threshold for simple cycle turbines to between 29 to 35 percent (depending on the design efficiency) and to between 40 to 49 percent for combined cycle turbines (depending on the design efficiency). The specific approach the EPA solicited comment on was reducing the design efficiency by 6 percent (*e.g.,* multiplying by 0.94) when determining the electric sales threshold. Some commenters supported lowering the proposed electric sales threshold while others supported maintaining the proposed standards.

After considering comments, in 40 CFR part 60, subpart TTTTa, the EPA has determined it is appropriate to eliminate the sliding scale electric sales threshold based on the design efficiency and instead base the subcategorization thresholds on fixed electric sales (also referred to sometimes here as capacity factor). In 40 CFR part 60 subpart TTTTa, the EPA is finalizing that the fixed electric sales threshold between intermediate load combustion turbines and base load combustion turbines is 40 percent. The 40 percent electric sales (capacity factor) threshold reflects the maximum capacity factor for intermediate load simple cycle turbines and the minimum prorated efficiency approach for base load combined cycle turbines that the EPA solicited comment on in proposal.[724]

The base load electric sales threshold is appropriate for new combustion turbines because, as will be discussed later, the first component of BSER for base load turbines is based on highly efficient combined cycle generation. Combined cycle units are significantly more efficient than simple cycle turbines; and therefore, in general, the EPA should be focusing its determination of the BSER for base load units on that more efficient technology. The electric sales thresholds and the emission standards are related because, at lower capacity factors, combustion turbines tend to have more variable operation (*e.g.,* more starts and stops and operation at part load conditions) that reduces the efficiency of the combustion turbine. This is particularly the case for combined cycle turbines because while the turbine engine can come to full load relatively quickly, the HRSG and steam turbine cannot, and combined cycle turbines responding to highly variable load will have efficiencies similar to simple cycle turbines.[725] This has implications for the appropriate control technologies and corresponding emission reduction potential. The EPA determined the final standard of performance based on review of emissions data for recently installed combined cycle combustion turbines with 12-operating month capacity factors of 40 percent or greater. The EPA considered a capacity factor threshold lower than 40 percent. However, expanding the subcategory to include combustion turbines with a 12-operating month electric sales of less than 40 percent would require the EPA to consider the emissions performance of combined cycle turbines operating at lower capacity factors and, while it would expand the number of sources in the base load subcategory, it would also result in a higher (*i.e.,* less stringent) numerical emission standard for the sources in the category.

Direct comparison of the costs of combined cycle turbines relative to simple cycle turbines can be challenging because model plant costs are often for combustion turbines of different sizes and do not account for variable operation. For example, combined cycle turbine model plants are generally for an EGU that is several hundred megawatts while simple cycle turbine model plants are generally less than a hundred megawatts. Direct comparison of the LCOE from these model plants is not relevant because the facilities are not comparable. Consider a facility with a block of 10 simple cycle turbines that are each 50 MW (so the overall facility capacity is 500 MW). Each simple cycle turbine operates as an individual unit and provides a different value to the electric grid as compared to a single 500 MW combined cycle turbine. While the minimum load of the combined cycle facility might be 200 MW, the block of 10 simple cycle turbines can provide from approximately 20 MW to 500 MW to the electric grid.

A more accurate cost comparison accounts for economies of scale and estimates the cost of a combined cycle turbine with the same net output as a simple cycle turbine. Comparing the modeled LCOE of these combustion turbines provides a meaningful comparison, at least for base load combustion turbines. Without accounting for economies of scale and variable operation, combined cycle turbines can appear to be more cost effective than simple cycle turbines under almost all conditions. In addition, without accounting for economies of scale, large frame simple cycle turbines can appear to be more cost effective than higher efficiency aeroderivative simple cycle turbines, even if operated at a 100 percent capacity factor. These cost models are not intended to make direct comparisons, and the EPA appropriately accounted for economies of scale when estimating the cost of the BSER. Since base load combustion turbines tend to operate under steady state conditions with few starts and stops, startup and shutdown costs and the efficiency impact of operating at variable loads are not important for determining the compliance costs of base load combustion turbines.

Based on an adjusted model plant comparison, combined cycle EGUs have a lower LCOE at capacity factors above approximately 40 percent compared to simple cycle EGUs operating at the same capacity factors. This supports the final base load fixed electric sales threshold of 40 percent for simple cycle turbines because it would be cost-effective for owners/operators of simple cycle turbines to add heat recovery if they elected to operate at higher capacity factors as a base load unit. Furthermore, based on an analysis of monthly emission rates, recently constructed combined cycle EGUs maintain consistent emission rates at capacity factors of less than 55 percent (which is the base load electric sales threshold in subpart TTTT) relative to operation at higher capacity factors. Therefore, the base load subcategory operating range can be expanded in 40 CFR part 60, subpart TTTTa, without impacting the stringency of the numeric standard. However, at capacity factors of less than approximately 40 percent, emission rates of combined cycle EGUs increase relative to their operation at higher capacity factors. It takes much longer for a HRSG to begin producing steam that can be used to generate additional electricity than it takes a combustion engine to reach full power. Under operating conditions with a significant number of starts and stops, typical of some intermediate and especially low load combustion turbines, there may not be enough time for the HRSG to generate steam that can be used for additional electrical generation. To maximize overall efficiency, combined cycle EGUs often use combustion turbine engines that are less efficient than the most

[724] The EPA solicited comment on basing the electric sales threshold on a value calculated using 0.94 times the design efficiency.

[725] This discussion assumes that the combined cycle turbine incorporates a bypass stack that allows the combustion turbine engine to operate independent of the HRSG/steam turbine. Without a bypass stack the combustion turbine engine could not come to full load as quickly.

efficient simple cycle turbine engines. Under operating conditions with frequent starts and stops where the HRSG does not have sufficient time to begin generating additional electricity, a combined cycle EGU may be no more efficient than a highly efficient simple cycle EGU. These distinctions in operation are thus meaningful for determining which emissions control technologies are most appropriate for types of units. Once a combustion turbine unit exceeds approximately 40 percent annual capacity factor, it is economical to add a HRSG which results in the unit becoming both more efficient and less likely to cycle its operation. Such units are, therefore, better suited for more stringent emission control technologies including CCS.

After the 2015 NSPS was finalized, some stakeholders expressed concerns about the approach for distinguishing between base load and non-base load turbines. They posited a scenario in which increased utilization of wind and solar resources, combined with low natural gas prices, would create the need for certain types of simple cycle turbines to operate for longer time periods than had been contemplated when the 2015 NSPS was being developed. Specifically, stakeholders have claimed that in some regional electricity markets with large amounts of variable renewable generation, some of the most efficient new simple cycle turbines—aeroderivative turbines—could be called upon to operate at capacity factors greater than their design efficiency. However, if those new simple cycle turbines were to operate at those higher capacity factors, they would become subject to the more stringent standard of performance for base load turbines. As a result, according to these stakeholders, the new aeroderivative turbines would have to curtail their generation and instead, less-efficient existing turbines would be called upon to run by the regional grid operators, which would result in overall higher emissions. The EPA evaluated the operation of simple cycle turbines in areas of the country with relatively large amounts of variable renewable generation and did not find a strong correlation between the percentage of generation from the renewable sources and the 12-operating month capacity factors of simple cycle turbines. In addition, most of the simple cycle turbines that commenced operation between 2010 and 2016 (the most recent simple cycle turbines not subject to 40 CFR part 60, subpart TTTT) have operated well below the base load electric sales threshold in 40 CFR part 60, subpart TTTT. Therefore, the Agency does not believe that the concerns expressed by stakeholders necessitates any revisions to the regulatory scheme. In fact, as noted above, the EPA is finalizing that the electric sales threshold can be lowered without impairing the availability of simple cycle turbines where needed, including to support the integration of variable generation. The EPA believes that the final threshold is not overly restrictive since a simple cycle turbine could operate on average for more than 9 hours a day in the intermediate load subcategory.

iii. Low and Intermediate Load Subcategories

This section discusses the EPA's rationale for subcategorizing non-base load combustion turbines into two subcategories—low load and intermediate load.

(A) Low Load Subcategory

The EPA proposed and is finalizing in 40 CFR part 60, subpart TTTTa, a low load subcategory to includes combustion turbines that operate only during periods of peak electric demand (*i.e.,* peaking units), which will be separate from the intermediate load subcategory. Low load combustion turbines also provide ramping capability and other ancillary services to support grid reliability. The EPA evaluated the operation of recently constructed simple cycle turbines to understand how they operate and to determine at what electric sales level or capacity factor their emissions rate is relatively steady. (Note that for purposes of this discussion, the terms ''electric sales'' and ''capacity factor'' are used interchangeably.) Low load combustion turbines generally only operate for short periods of time and potentially at relatively low duty cycles.[726] This type of operation reduces the efficiency and increases the emissions rate, regardless of the design efficiency of the combustion turbine or how it is maintained. For this reason, it is difficult to establish a reasonable output-based standard of performance for low load combustion turbines.

To determine the electric sales threshold—that is, to distinguish between the intermediate load and low load subcategories—the EPA evaluated capacity factor electric sales thresholds of 10 percent, 15 percent, 20 percent, and 25 percent. The EPA proposed to find and is finalizing a conclusion that the 10 percent threshold is problematic for two reasons. First, simple cycle turbines operating at that level or lower have highly variable emission rates, and therefore it is difficult for the EPA to establish a meaningful output-based standard of performance. In addition, only one-third of simple cycle turbines that have commenced operation since 2015 have maintained 12-operating month capacity factors of less than 10 percent. Therefore, setting the threshold at this level would bring most new simple cycle turbines into the intermediate load subcategory, which would subject them to a more stringent emission rate that is only achievable for simple cycle turbines operating at higher capacity factors. This could create a situation where simple cycle turbines might not be able to comply with the intermediate load standard of performance while operating at the low end of the intermediate load capacity factor subcategorization criteria.

Based on the EPA's review of hourly emissions data, at a capacity factor above 15 percent, GHG emission rates for many simple cycle turbines begin to stabilize. At higher capacity factors, more time is typically spent at steady state operation rather than ramping up and down; and emission rates tend to be lower while in steady-state operation. Of recently constructed simple cycle turbines, half have maintained 12-operating month capacity factors of 15 percent or less, two-thirds have maintained capacity factors of 20 percent or less; and approximately 80 percent have maintained maximum capacity factors of 25 percent or less. The emission rates clearly stabilize for most simple cycle turbines operating at capacity factors of greater than 20 percent. Based on this information, the EPA proposed the low load electric sales threshold—again, the dividing line to distinguish between the intermediate and low load subcategories—to be 20 percent and solicited comment on a range of 15 to 25 percent. The EPA also solicited comment on whether the low load electric sales threshold should be determined by a site-specific threshold based on three-fourths of the design efficiency of the combustion turbine.[727]Under this approach, simple

[726] The duty cycle is the average operating capacity factor. For example, if an EGU operates at 75 percent of the fully rated capacity, the duty cycle would be 75 percent regardless of how often the EGU actually operates. The capacity factor is a measure of how much an EGU is operated relative to how much it could potentially have been operated.

[727] The calculation used to determine the electric sales threshold includes both the design efficiency and the base load rating. Since the base load rating stays the same when adjusting the numeric value of the design efficiency for applicability purposes, adjustments to the design efficiency has twice the impact. Specifically, using three-fourths of the

cycle turbines selling less than 18 to 22 percent of their potential electric output (depending on the design efficiency) would still have been considered low load combustion turbines. This ''sliding scale'' electric sales threshold approach is like the approach the EPA used in the 2015 NSPS to recognize the environmental benefit of installing the most efficient combustion turbines for low load applications. Using this approach, combined cycle EGUs would have been able to sell between 26 to 31 percent of their potential electric output while still being considered low load combustion turbines. Some commenters supported a lower electric sales threshold while others supported a higher threshold. Based on these comments, the EPA is finalizing the proposed low load electric sales threshold of 20 percent of the potential electric sales. The fixed 20 percent capacity factor threshold represents a level of utilization at which most simple cycle combustion turbines perform at a consistent level of efficiency and GHG emission performance, enabling the EPA to establish a standard of performance that reflects a BSER of efficient operation. The 20 percent capacity factor threshold is also more environmentally protective than the higher thresholds the EPA considered, since owners and operators of combustion turbines operating above a 20 percent capacity factor would be subject to an output-based emissions standard instead of a heat input-based emissions standard based on the use of lower-emitting fuels. This ensures that owners/operators of intermediate load combined cycle turbines properly maintain and operate their combustion turbines.

(B) Intermediate Load Subcategory

The proposed sliding scale subcategorization approach essentially included two subcategories within the proposed intermediate load subcategory. As proposed, simple cycle turbines would be classified as intermediate load combustion turbines when operated between capacity factors of 20 percent and approximately 40 percent while combined cycle turbines would be classified as intermediate load combustion turbines when operated between capacity factors of 20 percent to approximately 55 percent. Owners/operators of combined cycle turbines operating at the high end of the intermediate load subcategory would only be subject to an emissions standard based on a BSER of high-efficiency simple cycle turbine technology. The proposed approach provided a regulatory incentive for owners/operators to purchase the most efficient technologies in exchange for additional compliance flexibility. The use of a prorated efficiency the EPA solicited comment on would have lowered the simple cycle and combined cycle turbine thresholds to approximately 35 percent and 50 percent, respectively.

In this final rule, the BSER for the intermediate load subcategory is consistent with the proposal—high-efficiency simple cycle turbine technology. While not specifically identified in the proposal, the BSER for the base load subcategory is also consistent with the proposal—the use of combined cycle technology.[728]

The 12-operating month electric sales (*i.e.,* capacity factor) thresholds for the stationary combustion turbine subcategories in this final rule are summarized below in Table 2.

TABLE 2—SALES THRESHOLDS FOR SUBCATEGORIES OF COMBUSTION TURBINE EGUS

Subcategory	12-Operating month electric sales threshold (percent of potential electric sales)
Low Load	≤20
Intermediate Load	>20 and ≤40
Base Load	>40

iv. Integrated Onsite Generation and Energy Storage

Integrated equipment is currently included as part of the affected facility, and the EPA proposed and is finalizing amended regulatory text to clarify that the output from integrated renewables is included as output when determining the NSPS emissions rate. The EPA also proposed that the output from the integrated renewable generation is not included when determining the net electric sales for applicability purposes (*i.e.,* generation from integrated renewables would not be considered when determining if a combustion turbine is subcategorized as a low, intermediate, or base load combustion turbine). In the alternative, the EPA solicited comment on whether instead of exempting the generation from the integrated renewables from counting toward electric sales, the potential output from the integrated renewables would be included when determining the design efficiency of the facility. Since the design efficiency is used when determining the electric sales threshold this would increase the allowable electric sales for subcategorization purposes. Including the integrated renewables when determining the design efficiency of the affected facility has the impact of increasing the operational flexibility of owners/operators of combustion turbines. Commenters generally supported maintaining that integrated renewables are part of the affected facility and including the output of the renewables when determining the emissions rate of the affected facility.[729] Therefore, the Agency is finalizing a decision that the rated output of integrated renewables be included when determining the design efficiency of the affected facility, which is used to determine the potential electric output of the affected facility, and that the output of the integrated renewables be included in determining the emissions rate of the affected facility. However, since the design efficiency is not a factor in determining the subcategory thresholds in 40 CFR part 60, subpart TTTTa, the output of the integrated renewables will not be included for determining the applicable subcategory. If the output from the integrated renewable generation were included for subcategorization purposes, this could discourage the use of integrated renewables (or curtailments) because affected facilities could move to a subcategory with a more stringent emissions standard that could cause the owner/operator to be out of compliance. The impact of this approach is that the electric sales threshold of the combustion turbine island itself, not including the integrated renewables, for an owner/operator of a combustion turbine that includes integrated renewables that increase the potential electric output by 1 percent would be 1 or 2 percent higher for the stationary combustion turbine island not considering the integrated renewables, depending on the design efficiency of the combustion turbine itself, than an identical combustion turbine without integrated renewables. In addition, when the output from the integrated renewables is considered, the output from the integrated renewables

design efficiency reduces the electric sales threshold by half.

[728] Under the proposed subcategorization approach, for a combustion turbine to be subcategorized as an intermediate load combustion turbine while operating at capacity factors of greater than 40 percent required the use of a HRSG (*e.g.,* combined cycle turbine technology).

[729] The EPA did not propose to include, and is not finalizing including, integrated renewables as part of the BSER. Commenters opposed a BSER that would include integrated renewables as part of the BSER. Commenters noted that this could result in renewables being installed in suboptimal locations which could result in lower overall GHG reductions.

lowers the emissions rate of the affected facility by approximately 1 percent.

For integrated energy storage technologies, the EPA solicited comment on and is finalizing a decision to include the rated output of the energy storage when determining the design efficiency of the affected facility. Similar to integrated renewables, this increases the flexibility of owner/operators to sell larger amounts of electricity while remaining in the low, variable, and intermediate load subcategories. While energy storage technologies have high capital costs, operating costs are low and would dispatch prior to the combustion turbine the technology is integrated with. Therefore, simple cycle turbines with integrated energy storage would likely operate at lower capacity factors than an identical simple cycle turbine at the same location. However, while the energy storage might be charged with renewables that would otherwise be curtailed, there is no guarantee that low emitting generation would be used to charge the energy storage. Therefore, the output from the energy storage is not considered in either determining the NSPS emissions rate or as net electric sales for subcategorization applicability purposes. In future rulemaking the Agency could further evaluate the impact of integrated energy storage on the operation of simple cycle turbines to determine if the number of starts and stops are reduced and increases the efficiency of simple cycle turbines relative to simple cycle turbines without integrated energy storage. If this is the case, it could be appropriate to lower the threshold for combustion turbines subject to a lower emitting fuels BSER because emission rates would be stable at lower capacity factors.

v. Definition of System Emergency

In 2015, the EPA included a provision that electricity sold during hours of operation when a unit is called upon due to a system emergency is not counted toward the percentage electric sales subcategorization threshold in 40 CFR part 60, subpart TTTT.[730] The Agency concluded that this exclusion is necessary to provide flexibility, maintain system reliability, and minimize overall costs to the sector.[731] The intent is that the local grid operator will determine the EGUs essential to maintaining grid reliability. Subsequent to the 2015 NSPS, members of the regulated community informed the EPA that additional clarification of a system emergency is needed to determine and document generation during system emergencies. The EPA proposed to include the system emergency approach in 40 CFR part 60, subpart TTTTa, and solicited comment on amending the definition of system emergency to clarify in implementation in 40 CFR part 60, subparts TTTT and TTTTa. Commenters generally agreed with the proposal to allow owners/operators of EGUs called upon during a system emergency to operate without impacting the EGUs' subcategorization (*i.e.,* electric sales during system emergencies would not be considered when determining net electric sales), and that the Agency should clarify how system emergencies are determined and documented.

In terms of the definition of the system emergency provision, commenters stated that ''abnormal'' be deleted from the definition, and instead of referencing ''the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator,'' the definition should reference ''the balancing authority or reliability coordinator.'' This change would align the regulation's definition with the terms used by NERC. Some commenters also stated that the EPA should specify that electric sales during periods the grid operator declares energy emergency alerts (EEA) levels 1 through 3 be included in the definition of system emergency.[732] In addition, some commenters stated that the definition should be expanded to include the concept of energy emergencies. Specifically, the definition should also exempt generation during periods when a load-serving entity or balancing authority has exhausted all other resource options and can no longer meet its expected load obligations. Finally, commenters stated that the definition should apply to all EGUs, regardless of if they are already operating when the system emergency is declared. This would avoid regulatory incentive to come offline prior to a potential system emergency to be eligible for the electric sales exemption and would treat all EGUs similarly during system emergencies (*i.e.,* not penalize EGUs that are already operating to maintain grid reliability and avoiding the need to declare grid emergencies).

The Agency is including the system emergency concept in 40 CFR part 60, subpart TTTTa, along with a definition that clarifies how to determine generation during periods of system emergencies. The EPA agrees with commenters that the definition of system emergency should be clarified and that it should not be limited to EGUs not operating when the system emergency is declared. Based on information provided by entities with reliability expertise, the EPA has determined that a system emergency should be defined to include EEA levels 2 and 3. These EEA levels generally correspond to time-limited, well-defined, and relatively infrequent situations in which the system is experiencing an energy deficiency. During EEA level 2 and 3 events, all available generation is online and demand-response or other load management procedures are in effect, or firm load interruption is imminent or in progress. The EPA believes it is appropriate to exclude hours of operation during such events in order to ensure that EGUs are not impeded from maintaining or increasing their output as needed to respond to a declared energy emergency. Because these events tend to be short, infrequent, and well-defined, the EPA also believes any incremental GHG emissions associated with operations during these periods would be relatively limited.

The EPA has determined not to include EEA level 1 in the definition of a ''system emergency.'' The EPA's understanding is that EEA level 1 events often include situations in which an energy deficiency does not yet exist, and in which balancing authorities are preparing to pursue various options for either bringing additional resources online or managing load. The EPA also understands that EEA level 1 events tend to be more frequently declared, and longer in duration, than level 2 or 3 events. Based on this information, the EPA believes that including EEA level 1 events in the definition of a ''system emergency'' would carry a greater risk of increasing overall GHG emissions without making a meaningful contribution to supporting reliability. This approach balances the need to have operational flexibility when the grid may be strained to help ensure that all available generating sources are available for grid reliability, while balancing with important considerations about potential GHG emission tradeoffs. The EPA is also amending the definition in 40 CFR part 60, subpart TTTT, to be

[730] In 40 CFR part 60, subpart TTTT, electricity sold by units that are not called upon to operate due to a system emergency (*e.g.,* units already operating when the system emergency is declared) is counted toward the percentage electric sales threshold.

[731] See 80 FR 64612; October 23, 2015.

[732] Commenters noted that grid operators have slightly different terms for grid emergencies, but example descriptions include: EEA 1, all available generation online and non-firm wholesale sales curtailed; EEA 2, load management procedures in effect, all available generation units online, demand-response programs in effect; and EEA 3, firm load interruption is imminent or in progress.

consistent with the definition in 40 CFR part 60, subpart TTTTa.

Commenters also added that operation during system emergencies should be subject to alternate standards of performance (*e.g.,* owners/operators are not required to use the CCS system during system emergencies to increase power output). The EPA agrees with commenters that since system emergencies are defined and historically rare events, an alternate standard of performance should apply during these periods. Carbon capture systems require significant amounts of energy to operate. Allowing owners/operators of EGUs equipped with CCS systems to temporarily reduce the capture rate or cease capture will increase the electricity available to end users during system emergencies. In place of the applicable output-based emissions standard, the owner/operator of an intermediate or base load combustion turbine would be subject to a BSER based on the combustion of lower-emitting fuels during system emergencies.[733] The emissions and output would not be included when calculating the 12-operating month emissions rate. The EPA considered an alternate emissions standard based on efficient generation but rejected that for multiple reasons. First, since system emergencies are limited in nature the emissions calculation would include a limited number of hours and would not necessarily be representative of an achievable longer-term emissions rate. In addition, EGUs that are designed to operate with CCS will not necessarily operate as efficiently without the CCS system operating compared to a similar EGU without a CCS system. Therefore, the Agency is not able to determine a reasonable efficiency-based alternate emissions standard for periods of system emergencies. Due to both the costs and time associated with starting and stopping the CCS system, the Agency has determined it is unlikely that an owner/operator of an affected facility would use it where it is not needed. System emergencies have historically been relatively brief and any hours of operation outside of the system emergencies are included when determining the output-based emissions standard. During short-duration system emergencies, the costs associated with stopping and starting the CCS system could outweigh the increased revenue from the additional electric sales. In addition, the time associated with starting and stopping a CCS system would likely result in an EGU operating without the CCS system in operation during periods of non-system emergencies. This would require the owner/operator to overcontrol during other periods of operation to maintain emissions below the applicable standard of performance. Therefore, it is likely an owner/operator would unnecessarily adjust the operation of the CCS system during EEA levels 2 and 3.

In addition to these measures, DOE has authority pursuant to section 202(c) of the Federal Power Act to, on its own motion or by request, order, among other things, the temporary generation of electricity from particular sources in certain emergency conditions, including during events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements. Such orders may be issued for 90 days and may be extended in 90-day increments after consultation with the EPA. DOE has historically issued section 202(c) orders at the request of electric generators and grid operators such as RTOs in order to enable the supply of additional generation in times of expected emergency-related generation shortfalls.

c. Multi-Fuel-Fired Combustion Turbines

In 40 CFR part 60, subpart TTTT, multi-fuel-fired combustion turbines are subcategorized as EGUs that combust 10 percent or more of fuels not meeting the definition of natural gas on a 12-operating month rolling average basis. The BSER for this subcategory is the use of lower-emitting fuels with a corresponding heat input-based standard of performance of 120 to 160 lb CO_2/MMBtu, depending on the fuel, for newly constructed and reconstructed multi-fuel-fired stationary combustion turbines.[734] Lower-emitting fuels for these units include natural gas, ethylene, propane, naphtha, jet fuel kerosene, Nos. 1 and 2 fuel oils, biodiesel, and landfill gas. The definition of natural gas in 40 CFR part 60, subpart TTTT, includes fuel that maintains a gaseous state at ISO conditions, is composed of 70 percent by volume or more methane, and has a heating value of between 35 and 41 megajoules (MJ) per dry standard cubic meter (dscm) (950 and 1,100 Btu per dry standard cubic foot). Natural gas typically contains 95 percent methane and has a heating value of 1,050 Btu/lb.[735] A potential issue with the multi-fuel subcategory is that owners/operators of simple cycle turbines can elect to burn 10 percent non-natural gas fuels, such as Nos. 1 or 2 fuel oil, and thereby remain in that subcategory, regardless of their electric sales. As a result, they would remain subject to the less stringent standard that applies to multi-fuel-fired sources, the lower-emitting fuels standard. This could allow less efficient combustion turbine designs to operate as base load units without having to improve efficiency and could allow EGUs to avoid the need for efficient design or best operating and maintenance practices. These potential circumventions would result in higher GHG emissions.

To avoid these outcomes, the EPA proposed and is finalizing a decision not to include the multi-fuel subcategory for low, intermediate, and base load combustion turbines in 40 CFR part 60, subpart TTTTa. This means that new multi-fuel-fired turbines that commence construction or reconstruction after May 23, 2023, will fall within a particular subcategory depending on their level of electric sales. The EPA also proposed and is finalizing a decision that the performance standards for each subcategory be adjusted appropriately for multi-fuel-fired turbines to reflect the application of the BSER for the subcategories to turbines burning fuels with higher GHG emission rates than natural gas. To be consistent with the definition of lower-emitting fuels in the 2015 NSPS, the maximum allowable heat input-based emissions rate is 160 lb CO_2/MMBtu. For example, a standard of performance based on efficient generation would be 33 percent higher for a fuel oil-fired combustion turbine compared to a natural gas-fired combustion turbine. This assures that the BSER, in this case efficient generation, is applied, while at the same time accounting for the use of multiple fuels.

[733] For owners/operators of combustion turbines the lower emitting fuels requirement is defined to include fuels with an emissions rate of 160 lb CO_2/MMBtu or less. For owners/operators of steam generating units or IGCC facilities the EPA is requiring the use of the maximum amount of non-coal fuels available to the affected facility.

[734] Combustion turbines co-firing natural gas with other fuels must determine fuel-based site-specific standards at the end of each operating month. The site-specific standards depend on the amount of co-fired natural gas. 80 FR 64616 (October 23, 2015).

[735] Note that according to 40 CFR part 60, subpart TTTT, combustion turbines co-firing 25 percent hydrogen by volume could be subcategorized as multi-fuel-fired EGUs because the percent methane by volume could fall below 70 percent, the heating value could fall below 35 MJ/Sm^3, and 10 percent of the heat input could be coming from a fuel not meeting the definition of natural gas.

d. Rural Areas and Small Utility Distribution Systems

As part of the original proposal and during the Small Business Advocacy Review (SBAR) outreach the EPA solicited comment on creating a subcategory for rural electric cooperatives and small utility distribution systems (serving 50,000 customers or less). Commenters expressed concerns that a BSER based on either co-firing hydrogen or CCS may present an additional hardship on economically disadvantaged communities and on small entities, and that the EPA should evaluate potential increased energy costs, transmission upgrade costs, and infrastructure encroachment which may directly affect the disproportionately impacted communities. As described in section VIII.F, the BSER for new stationary combustion turbines does not include hydrogen co-firing and CCS qualifies as the BSER for base load combustion turbines on a nationwide basis. Therefore, the EPA has determined that a subcategory for rural cooperatives and/or small utility distribution systems is not appropriate.

F. Determination of the Best System of Emission Reduction (BSER) for New and Reconstructed Stationary Combustion Turbines

In this section, the EPA describes the technologies it proposed as the BSER for each of the subcategories of new and reconstructed combustion turbines that commence construction after May 23, 2023, as well as topics for which the Agency solicited comment. In the following section, the EPA describes the technologies it is determining are the final BSER for each of the three subcategories of affected combustion turbines and explains its basis for selecting those controls, and not others, as the final BSER. The controls that the EPA evaluated included combusting non-hydrogen lower-emitting fuels (*e.g.,* natural gas and distillate oil), using highly efficient generation, using CCS, and co-firing with low-GHG hydrogen.

For the low load subcategory, the EPA proposed the use of lower-emitting fuels as the BSER. This was consistent with the BSER and performance standards established in the 2015 NSPS for the non-base load subcategory as discussed earlier in section VIII.C.

For the intermediate load subcategory, the EPA proposed an approach under which the BSER was made up of two components: (1) highly efficient generation; and (2) co-firing 30 percent (by volume) low-GHG hydrogen. Each component of the BSER represented a different set of controls, and those controls formed the basis of corresponding standards of performance that applied in two phases. Specifically, the EPA proposed that affected facilities (*i.e.,* facilities that commence construction or reconstruction after May 23, 2023) could apply the first component of the BSER (*i.e.,* highly efficient generation) upon initial startup to meet the first phase of the standard of performance. Then, by 2032, the EPA proposed that affected facilities could apply the second component of the BSER (*i.e.,* co-firing 30 percent (by volume) low-GHG hydrogen) to meet a second and more stringent standard of performance. The EPA also solicited comment on whether the intermediate load subcategory should apply a third component of the BSER: co-firing 96 percent (by volume) low-GHG hydrogen by 2038. In addition, the EPA solicited comment on whether the low load subcategory should also apply the second component of BSER, co-firing 30 percent (by volume) low-GHG hydrogen, by 2032. The Agency proposed that these latter components of the BSER would continue to include the application of highly efficient generation.

For the base load subcategory, the EPA also proposed a multi-component BSER and multi-phase standard of performance. The EPA proposed that each new base load combustion turbine would be required to meet a phase-1 standard of performance based on the application of the first component of the BSER—highly efficient generation—upon initial startup of the affected source. For the second component of the BSER, the EPA proposed two potential technology pathways for base load combustion turbines with corresponding standards of performance. One proposed technology pathway was 90 percent CCS, which base load combustion turbines would install and begin to operate by 2035 to meet the phase-2 standard of performance. A second proposed technology pathway was co-firing low-GHG hydrogen, which base load combustion turbines would implement in two steps: (1) By co-firing 30 percent (by volume) low-GHG hydrogen to meet the phase-2 standard of performance by 2032, and (2) by co-firing 96 percent (by volume) low-GHG hydrogen to meet a phase 3 standard of performance by 2038. Throughout, the Agency proposed base load turbines, like intermediate load turbines, would remain subject to the first component of the BSER based on highly efficient generation.

The proposed approach reflected the EPA's view that the BSER components for the intermediate load and base load subcategories could achieve deeper reductions in GHG emissions by implementing CCS and co-firing low-GHG hydrogen. This proposed approach also recognized that building the infrastructure required to support widespread use of CCS and low-GHG hydrogen technologies in the power sector will take place on a multi-year time scale. Accordingly, new and reconstructed facilities would be aware of their need to ramp toward more stringent phases of the standards, which would reflect application of the more stringent controls in the BSER. This would occur either by co-firing a lower percentage (by volume) of low-GHG hydrogen by 2032 and a higher percentage (by volume) of low-GHG hydrogen by 2038, or with installation and use of CCS by 2035. The EPA also solicited comment on the potential for an earlier compliance date for the second phase.

For the base load subcategory, the EPA proposed two potential BSER pathways because the Agency believed there was more than one viable technology for these combustion turbines to significantly reduce their CO_2 emissions. The Agency also found value in receiving comments on, and potentially finalizing, both BSER pathways to enable project developers to elect how they would reduce their CO_2 emissions on timeframes that make sense for each BSER pathway.[736] The EPA solicited comment on whether the co-firing of low-GHG hydrogen should be considered a compliance pathway for sources to meet a single standard of performance based on the application of CCS rather than a separate BSER pathway. The EPA proposed that there would be earlier opportunities for units to begin co-firing lower amounts of low-GHG hydrogen than to install and begin operating 90 percent CCS systems. However, the Agency proposed that it would likely take longer for those units to increase their co-firing to significant quantities of low-GHG hydrogen. Therefore, in the proposal, the EPA presented the BSER pathways as separate subcategories and solicited comment on the option of finalizing a single standard of performance based on the application of CCS.

For the low load subcategory, the EPA proposed and is finalizing that the BSER is the use of lower-emitting fuels. For the intermediate load subcategory, the EPA proposed and is finalizing that the

[736] The EPA recognizes that standards of performance are technology neutral and that a standard based on application of CCS could be achieved by co-firing hydrogen.

BSER is highly efficient generating technology—simple cycle technology as well as operating and maintaining it efficiently.[737] The EPA is not finalizing a second component of the BSER or a phase-2 standard of performance for intermediate load combustion turbines at this time. For the base load subcategory, the EPA proposed and is finalizing that the first component of the BSER is highly efficient generating technology—combined cycle technology as well as operating and maintaining it efficiently. The EPA proposed and is finalizing a second component of the BSER or a phase-2 standard of performance for base load combustion turbines—efficient generation in combination with 90 percent CCS.

The EPA is not finalizing low-GHG hydrogen co-firing as the second component of the BSER for the intermediate load or base load combustion turbines at this time. (See section VIII.F.5.b for the EPA's explanation of this decision.) With respect to the CCS pathway for base load combustion turbines, the EPA is finalizing a second phase of the standards of performance that includes a single CCS BSER pathway, which includes the use of highly efficient generation and 90 percent CCS. Owners/operators of new and reconstructed base load combustion turbines will be required to meet the second phase standards of performance for 12-operating month rolling averages that begin on or after January 2032, that reflect application of both the phase-1 and phase-2 components of the BSER. Table 3 of this document summarizes the final BSER for combustion turbine EGUs that commence construction or reconstruction after May 23, 2023. The EPA is finalizing standards of performance based on those BSER for each subcategory, as discussed in section VIII.G.

TABLE 3—FINAL BSER FOR COMBUSTION TURBINE EGUS

Subcategory [1]	Fuel	1st Component BSER	2nd Component BSER
Low Load	All Fuels	lower-emitting fuels	N/A.
Intermediate Load	All Fuels	Highly Efficient Simple Cycle Generation.	N/A.
Base Load	All Fuels	Highly Efficient Combined Cycle Generation.	Highly Efficient Combined Cycle Generation Plus 90 Percent CCS Beginning in 2032.

[1] The low load subcategory is applicable to combustion turbines selling 20 percent or less of their potential electric output, the intermediate load subcategory is applicable to combustion turbines selling greater than 20 percent and less than or equal to 40 percent of their potential electric output, and the base load subcategory is applicable to combustion turbines selling greater than 40 percent of their potential electric output.

1. BSER for Low Load Subcategory

This section describes the BSER for the low load (*i.e.,* peaking) subcategory at this time, which is the use of lower-emitting fuels. The Agency proposed and is finalizing a determination that the use of lower-emitting fuels, which the EPA determined to be the BSER for the non-base load subcategory in the 2015 NSPS, is the BSER for this low load subcategory. As explained in section VIII.E.2.b, the EPA is narrowing the definition of the low load subcategory by lowering the electric sales threshold (as compared to the electric sales threshold for non-base load combustion turbines in the 2015 NSPS), so that combustion turbines with higher electric sales would be placed in the intermediate load subcategory and therefore be subject to a more stringent standard based on the more stringent BSER.

a. Background: The Non-Base Load Subcategory in the 2015 NSPS

The 2015 NSPS defined non-base load natural gas-fired EGUs as stationary combustion turbines that (1) burn more than 90 percent natural gas and (2) have net electric sales equal to or less than their design efficiency (not to exceed 50 percent) multiplied by their potential electric output (80 FR 64601; October 23, 2015). These are calculated on 12-operating month and 3-calendar year rolling average bases. The EPA also determined in the 2015 NSPS that the BSER for newly constructed and reconstructed non-base load natural gas-fired stationary combustion turbines is the use of lower-emitting fuels. Id. at 64515. These lower-emitting fuels are primarily natural gas with a small allowance for distillate oil (*i.e.,* Nos. 1 and 2 fuel oils), which have been widely used in stationary combustion turbine EGUs for decades.

The EPA also determined in the 2015 NSPS that the standard of performance for sources in this subcategory is a heat input-based standard of 120 lb CO_2/MMBtu. The EPA established this clean-fuels BSER for this subcategory because of the variability in the operation in non-base load combustion turbines and the challenges involved in determining a uniform output-based standard that all new and reconstructed non-base load units could achieve.

Specifically, in the 2015 NSPS, the EPA recognized that a BSER for the non-base load subcategory based on the use of lower-emitting fuels results in limited GHG reductions, but further recognized that an output-based standard of performance could not reasonably be applied to the subcategory. The EPA explained that a combustion turbine operating at a low capacity factor could operate with multiple starts and stops, and that its emission rate would be highly dependent on how it was operated and not its design efficiency. Moreover, combustion turbines with low annual capacity factors typically operated differently from each other, and therefore had different emission rates. The EPA recognized that, as a result, at the time it would not be possible to determine a standard of performance that could reasonably apply to all combustion turbines in the subcategory. For that reason, the EPA further recognized, efficient design [738] and operation would not qualify as the BSER; rather, the BSER should be lower-emitting fuels and the associated standard of performance should be based on heat input. Since the 2015 NSPS, all newly constructed simple cycle turbines have been non-base load units and thus have become subject to this standard of performance.

[737] The EPA sometimes refers to highly efficient generating technology in combination with the best operating and maintenance practices as highly efficient generation. The affected sources must meet standards based on this efficient generating technology upon the effective date of the final rule.

[738] Important characteristics for minimizing emissions from low load combustion turbines include the ability to operate efficiently while operating at part load conditions and the ability to rapidly achieve maximum efficiency to minimize periods of operation at lower efficiencies. These characteristics do not necessarily always align with higher design efficiencies that are determined under steady-state full-load conditions.

b. BSER

Consistent with the rationale of the 2015 NSPS, the EPA proposed and is finalizing that the use of fuels with an emissions rate of less than 160 lb CO_2/MMBtu (*i.e.,* lower-emitting fuels) meets the BSER requirements for the low load subcategory at this time. Use of these fuels is technically feasible for combustion turbines. Natural gas comprises the majority of the heat input for simple cycle turbines and is the lowest cost fossil fuel. In the 2015 NSPS, the EPA determined that natural gas comprised 96 percent of the heat input for simple cycle turbines. See 80 FR 64616 (October 23, 2015). Therefore, a BSER based on the use of natural gas and/or distillate oil would have minimal, if any, costs to regulated entities. The use of lower-emitting fuels would not have any significant adverse energy requirements or non-air quality or environmental impacts, as the EPA determined in the 2015 NSPS. *Id.* at 64616. In addition, the use of fuels meeting this criterion would result in some emission reductions by limiting the use of fuels with higher carbon content, such as residual oil, as the EPA also explained in the 2015 NSPS. *Id.* Although the use of fuels meeting this criterion would not advance technology, in light of the other reasons described here, the EPA proposed and is finalizing that the use of natural gas, Nos. 1 and 2 fuel oils, and other fuels [739] currently specified in 40 CFR part 60, subpart TTTT, qualify as the BSER for new and reconstructed combustion turbine EGUs in the low load subcategory at this time. The EPA also proposed including low-GHG hydrogen on the list of fuels meeting the uniform fuels criteria in 40 CFR part 60, subpart TTTTa. The EPA is finalizing the inclusion of hydrogen, regardless of the production pathway, on the list of fuels meeting the uniform fuels criteria in 40 CFR part 60, subpart TTTTa.[740] The addition of hydrogen (and fuels derived from hydrogen) to 40 CFR part 60, subpart TTTTa, simplifies the recordkeeping and reporting requirements for low load combustion turbines that elect to burn hydrogen.

For the reasons discussed in the 2015 NSPS and noted above, the EPA did not propose that efficient design and operation qualify as the BSER for the low load subcategory. The emissions rate of a low load combustion turbine is highly dependent upon the way the specific combustion turbine is operated. For example, a combustion turbine with multiple startups and shutdowns and operation at part loads will have high emissions relative to if it were operated at steady-state high-load conditions. Important characteristics for reducing GHG emissions from low load combustion turbines are the ability to minimize emissions during periods of startup and shutdown and efficient operation at part loads and while changing loads. If the combustion turbine is frequently operated at part-load conditions with frequent starts and stops, a combustion turbine with a high design efficiency, which is determined at full-load steady-state conditions, would not necessarily emit at a lower GHG rate than a combustion turbine with a lower design efficiency. In addition, combustion turbines with higher design efficiencies have higher initial costs compared to combustion turbines with lower design efficiencies. Since the EPA does not have sufficient information at this time to determine emission reduction for the subcategory it is not possible to determine the cost effectiveness of a BSER based on high efficiency simple cycle turbines.[741]

The EPA solicited comment on whether, and the extent to which, high-efficiency designs also operate more efficiently at part loads and can start more quickly and reach the desired load more rapidly than combustion turbines with less efficient design efficiencies. In addition, the EPA solicited comment on the cost premium of high-efficiency simple cycle turbines. To the extent the Agency received additional relevant information, the EPA was considering promulgating design standard requirements pursuant to CAA section 111(h). However, the EPA did not receive comments that changed the proposal conclusions.

The EPA did not propose the use of CCS or hydrogen co-firing as the BSER (or as a component of the BSER) for low load combustion turbines. The EPA did not propose that CCS is the BSER for simple cycle turbines based on the Agency's assessment that currently available post-combustion amine-based carbon capture systems require that the exhaust from a combustion turbine be cooled prior to entering the carbon capture equipment. The most energy efficient way to cool the exhaust gas is to use a HRSG, which is an integral component of a combined cycle turbine system but is not incorporated in a simple cycle unit. For this reason and due to the high costs of CCS for low load combustion turbines, the Agency did not propose and is not finalizing a determination that CCS qualifies as the BSER for this subcategory of sources.

The EPA did not propose low-GHG hydrogen co-firing as the BSER for low load combustion turbines because not all new combustion turbines can necessarily co-fire higher percentages of hydrogen, there are potential infrastructure issues specific to low load combustion turbines, and at the relatively infrequent levels of utilization that characterize the low load subcategory, a low-GHG hydrogen co-firing BSER would not necessarily result in cost-effective GHG reductions for all low load combustion turbines. As discussed later in this section, the Agency is not determining that low-GHG hydrogen co-firing qualifies as the BSER for combustion turbines. In future rulemaking the Agency could further evaluate the costs and emissions performance of other technologies to reduce emissions from low-load units to determine if other technologies qualify as the BSER.

2. BSER for Intermediate Load Subcategory

This section describes the BSER for new and reconstructed combustion turbines in the intermediate load subcategory. For combustion turbines in the intermediate load subcategory, the BSER is the use of high-efficiency simple cycle turbine technology in combination with the best operating and maintenance practices.

a. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the BSER for intermediate load combustion turbines because, as described earlier in this section, it would achieve few GHG emission reductions compared to highly efficient generation.

b. Highly Efficient Generation

This section includes a discussion of the various highly efficient generation technologies used by owners/operators of combustion turbines. The appropriate technology depends on how the combustion turbine is operated, and the EPA has determined it does not have sufficient information to determine an appropriate output-based emissions standard for low load combustion turbines. At higher capacity factors, emission rates for simple cycle combustion turbines are more consistent, and the EPA has sufficient

[739] The BSER for multi-fuel-fired combustion turbines subject to 40 CFR part 60, subpart TTTT, is also the use of fuels with an emissions rate of 160 lb CO_2/MMBtu or less. The use of these fuels will demonstrate compliance with the low load subcategory.

[740] The EPA is not finalizing a definition of low-GHG hydrogen.

[741] The cost effectiveness calculation is highly dependent upon assumptions concerning the increase in capital costs, the decrease in heat rate, and the price of natural gas.

information to determine a BSER other than lower-emitting fuels.

The use of highly efficient generating technology in combination with the best operating and maintenance practices has been demonstrated by multiple facilities for decades. Notably, over time, as technologies have improved, what is considered highly efficient has changed as well. Highly efficient generating technology is available and offered by multiple vendors for both simple cycle and combined cycle turbines. Both types of combustion turbines can also employ best operating and maintenance practices, which include routine operating and maintenance practices that minimize fuel use.

For simple cycle turbines, manufacturers continue to improve the efficiency by increasing firing temperature, increasing pressure ratios, using intercooling on the air compressor, and adopting other measures. These improved designs allow for improved operating efficiencies and reduced emission rates. Design efficiencies of simple cycle turbines range from 33 to 40 percent. Best operating practices for simple cycle turbines include proper maintenance of the combustion turbine flow path components and the use of inlet air cooling to reduce efficiency losses during periods of high ambient temperatures.

For combined cycle turbines, high-efficiency technology uses a highly efficient combustion turbine engine matched with a high-efficiency HRSG. The most efficient combined cycle EGUs use HRSG with three different steam pressures and incorporate a steam reheat cycle to maximize the efficiency of the Rankine cycle. It is not necessarily practical for owners/operators of combined cycle facilities using a turbine engine with an exhaust temperature below 593 °C or a steam turbine engine smaller than 60 MW to incorporate a steam reheat cycle. Smaller combustion turbine engines, less than those rated at approximately 2,000 MMBtu/h, tend to have lower exhaust temperatures and are paired with steam turbines of 60 MW or less. These smaller combined cycle units are limited to using a HRSG with three different steam pressures, but without a reheat cycle. This increases the heat rate of the combined cycle unit by approximately 2 percent. High efficiency also includes, but is not limited to, the use of the most efficient steam turbine and minimizing energy losses using insulation and blowdown heat recovery. Best operating and maintenance practices include, but are not limited to, minimizing steam leaks, minimizing air infiltration, and cleaning and maintaining heat transfer surfaces.

A potential drawback of combined cycle turbines with the highest design efficiencies is that the facility is relatively complicated and startup times can be relatively long. Combustion turbine manufacturers have invested in fast-start technologies that reduce startup times and improve overall efficiencies. According to the NETL Baseline Flexible Operation Report, while the design efficiencies are the same, the capital costs of fast-start combined cycle turbines are 1.6 percent higher than a comparable conventional start combined cycle facility.[742] The additional costs include design parameters that significantly reduce start times. However, fast-start combined cycle turbines are still significantly less flexible than simple cycle turbines and generally do not serve the same role. The startup time to full load from a hot start takes a simple cycle turbine 5 to 8 minutes, while a combined cycle turbines ranges from 30 minutes for a fast-start combined cycle turbine to 90 minutes for a conventional start combined cycle turbine. The startup time to full load from a cold start takes a simple cycle turbine 10 minutes, while a combined cycle turbines ranges from 120 minutes for a fast-start combined cycle turbine to 250 minutes for a conventional start combined cycle turbine. In addition, fast-start combined cycle turbines require the use of an auxiliary boiler during warm and cold starts.[743] In addition, minimum run times for simple cycle aeroderivative engines and combined cycle EGUs equal one minute and 120 minutes, respectively. Minimum downtime for the same group is five minutes and 60 minutes, respectively. Finally, simple cycle aeroderivative turbines have no limit to the number of starts per year. Combined cycle EGUs are limited in the number of starts, and additional maintenance costs will occur if the hours/start ratio drops below 25. The model combined cycle turbines in the NETL Baseline Flexible Operation Report use a HRSG with three different steam pressures and a reheat cycle. While the use of this type of HRSG increases design efficiencies at steady state conditions, it increases the capital costs and decreases the flexibility (*e.g.,* longer start times) of the combined cycle turbine. While less common, combined cycle turbines can be designed with a relatively simple HRSG that produces either a single or two pressures of steam without a reheat cycle. While design efficiencies are lower, the combined cycle turbines are more flexible and have the potential to operate similar to at least a portion of the simple cycle turbines in the intermediate load subcategory and provide the same value to the grid.

The EPA solicited comment on whether additional technologies for new simple and combined cycle EGUs that could reduce emissions beyond what is currently being achieved by the best performing EGUs should be included in the BSER. Specifically, the EPA sought comment on whether pressure gain combustion should be incorporated into a standard of performance based on an efficient generation BSER for both simple and combined cycle turbines. In addition, the EPA sought comment on whether the HRSG for combined cycle turbines should be designed to utilize supercritical steam conditions or to utilize supercritical CO_2 as the working fluid instead of water; whether useful thermal output could be recovered from a compressor intercooler and boiler blowdown; and whether fuel preheating should be implemented. Commenters generally noted that these technologies are promising, but that because the EPA did not sufficiently evaluate the BSER criteria in the proposal and none of these technologies should be incorporated as part of the BSER. The EPA continues to believe these technologies are promising, but the Agency is not including them as part of the BSER at this time.

The EPA also solicited comment on whether the use of steam injection is applicable to intermediate load combustion turbines. Steam injection is the use of a relatively simple and low-cost HRSG to produce steam, but instead of recovering the energy by expanding the steam through a steam turbine, the steam is injected into the compressor and/or through the fuel nozzles directly into the combustion chamber and the energy is extracted by the combustion turbine engine.[744] Advantages of steam injection include improved efficiency and increased output of the combustion turbine as well as reduced NO_X emissions. Combustion turbines using steam

[742] ''Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation.'' DOE/NETL–2023/3855. May 5, 2023.

[743] Fast start combined cycle turbine do not use an auxiliary boiler during hot starts and conventional start combined cycle turbine do not have auxiliary boilers.

[744] A steam injected combustion turbine would be considered a combined cycle combustion turbine (for NSPS purposes) because energy from the turbine engine exhaust is recovered in a HRSG and that energy is used to generate additional electricity.

injection have characteristics in-between simple cycle and combined cycle combustion turbines. They are more efficient, but more complex and have higher capital costs than simple cycle combustion turbines without steam injection. Conversely, compared to combined cycle EGUs, simple cycle combustion turbines using steam injection are simpler, have shorter construction times, and have lower capital costs, but have lower efficiencies.[745] [746] Combustion turbines using steam injection can start quickly, have good part-load performance, and can respond to rapid changes in demand, making the technology a potential solution for reducing GHG emissions from intermediate load combustion turbines. A potential drawback of steam injection is that the additional pressure drop across the HRSG can reduce the efficiency of the combustion turbine when the facility is running without the steam injection operating.

The EPA is aware of a limited number of combustion turbines that are using steam injection that have maintained 12-operating month emission rates of less than 1,000 lb CO_2/MWh-gross. Commenters stated that steam injection does not qualify as the BSER because it has not been adequately demonstrated and the EPA did not include sufficient analysis of the technology in the proposal to determine it as the BSER for intermediate load combustion turbines. The EPA continues to believe the technology is promising and it may be used to comply with the standard of performance, but the Agency is not determining that it is the BSER for intermediate load combustion turbines at this time. In a potential future rulemaking, the Agency could further evaluate the costs and emissions performance of steam injection to determine if the technology qualifies as the BSER.

i. Adequately Demonstrated

The EPA proposed and is finalizing that highly efficient simple cycle designs are adequately demonstrated because highly efficient simple cycle turbines have been demonstrated by multiple facilities for decades, the efficiency improvements of the most efficient designs are incremental in nature and do not change in any significant way how the combustion turbine is operated or maintained, and the levels of efficiency that the EPA is proposing have been achieved by many recently constructed combustion turbines. Therefore, efficient generation technology described in this BSER is commercially available and the standards of performance are achievable.

ii. Costs

In general, advanced generation technologies enhance operational efficiency compared to lower efficiency designs. Such technologies present little incremental capital cost compared to other types of technologies that may be considered for new and reconstructed sources. In addition, more efficient designs have lower fuel costs, which offsets at least a portion of the increase in capital costs.

For the intermediate load subcategory, the EPA considers that the costs of high-efficiency simple cycle combustion turbines are reasonable. As described in the subcategory section, the cost of combustion turbine engines is dependent upon many factors, but the EPA estimates that that the capital cost of a high-efficiency simple cycle turbine is 10 percent more than a comparable lower efficiency simple cycle turbine. Assuming all other costs are the same and that the high-efficiency simple cycle turbine uses 8 percent less fuel, high-efficiency simple cycle combustion turbines have a lower LCOE compared to standard efficiency simple cycle combustion turbines at a 12-operating month capacity factor of approximately 31 percent. At a 20 percent and 15 percent capacity factors, the compliance costs are $1.5/MWh and $35/metric ton and $3.0/MWh and $69/metric ton, respectively. The EPA has determined that the incremental costs the use of high efficiency simple cycle turbines as the BSER for intermediate load combustion turbines is reasonable. The EPA notes that the approach the Agency used to estimate these costs have a relatively high degree of uncertainty and are likely high given the common use of high efficiency simple cycle turbines without a regulatory driver.

The EPA considered but is not finalizing combined cycle unit design for combustion turbines as the BSER for the intermediate load subcategory because it is unclear if combined cycle turbines could serve the same role as intermediate load simple cycle turbines as a whole. Specifically, the EPA does not have sufficient information to determine that an intermediate load combined cycle turbine can start and stop with enough flexibility to provide the same level of grid support as intermediate load simple cycle turbines as a whole. In addition, the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear. Intermediate load combustion turbines start and stop so frequently that there would often not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

Some commenters agreed with the proposed rationale of the EPA, and other commenters disagreed and said that combined cycle turbine technology is cost effective and lower-emitting than simple cycle turbine technology and therefore qualifies as the BSER for intermediate load combustion turbines. Commenters supporting combined cycle technology as the BSER submitted cost information that indicated that combined cycle EGUs have lower capital costs and LCOE than simple cycle turbines. However, the commenters compared capital costs of larger combined cycle turbines to smaller simple cycle turbines and did not account for economies of scale. The EPA has concluded that the appropriate cost comparison is for combustion turbines with the same rated net output.[747] Comparing the costs of different size EGUs is not appropriate because these EGUs provide different grid services. In addition, the commenters did not account for startup costs and the time required for a steam turbine to begin operating when determining the LCOE.

The EPA considered the operation of simple cycle turbine to determine the potential for simple cycle turbine to add a HRSG while continuing to operate in the same manner, providing the same grid services, as current simple cycle turbines. As noted previously, aeroderivative simple cycle turbines have shorter run times per start than frame type simple cycle turbines at the same capacity factor. At an annual capacity factor of 20 percent, the median run time per start for aeroderivative and frame simple cycle turbines is 12 and 16 hours respectively. At an annual capacity factor of 30 percent, the average run times per start increase to 17 and 26 hours for aeroderivative and frame turbines respectively. The higher operating times of frame type simple cycle turbines,

[745] Bahrami, S., *et al.* (2015). *Performance Comparison between Steam Injected Gas Turbine and Combined Cycle during Frequency Drops.* Energies 2015, Volume 8. *https://doi.org/10.3390/en8087582.*

[746] Mitsubishi Power. *Smart-AHAT (Advanced Humid Air Turbine). https://power.mhi.com/products/gasturbines/technology/smart-ahat.*

[747] The costing approach used by the EPA compares a combined cycle turbine using a smaller turbine engine plus a steam turbine to match the output from a simple cycle turbine.

along with the larger size of frame type turbines, indicate that combined cycle technology could be applicable to at least a portion of intermediate load combustion turbines. In future rulemakings addressing GHGs from new as well as existing combustion turbines, the EPA intends to further evaluate the costs and potential emission reductions of the use of faster starting and lower cost HRSG technology for intermediate load combustion turbines to determine if the technology does in fact qualify as the BSER.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Use of highly efficient generation reduces all non-air quality health and environmental impacts and energy requirements assuming it displaces less efficient or higher-emitting generation. Even when operating at the same input-based emissions rate, the more efficient a unit is, the less fuel is required to produce the same level of output; and, as a result, emissions are reduced for all pollutants. The use of highly efficient combustion turbines, compared to the use of less efficient combustion turbines, reduces all pollutants.[748] By the same token, because improved efficiency allows for more electricity generation from the same amount of fuel, it will not have any adverse effects on energy requirements.

Designating highly efficient generation as part of the BSER for new and reconstructed intermediate load combustion turbines will not have significant impacts on the nationwide supply of electricity, electricity prices, or the structure of the electric power sector. On a nationwide basis, the additional costs of the use of highly efficient generation will be small because the technology does not add significant costs and at least some of those costs are offset by reduced fuel costs. In addition, at least some of these new combustion turbines would be expected to incorporate highly efficient generation technology in any event.

iv. Extent of Reductions in CO_2 Emissions

The EPA estimated the potential emission reductions associated with a standard that reflects the application of highly efficient generation as BSER for the intermediate load subcategory. As discussed in section VIII.G.1, the EPA determined that the standards of performance reflecting this BSER are 1,170 lb CO_2/MWh-gross for intermediate load combustion turbines.

Between 2015 and 2022, 113 simple cycle turbines, an average of 16 per year, commenced operation. Of these, 112 reported 12-operating month capacity factors. The EPA estimates that 23 simple cycle turbines operated at 12-operating month capacity factors greater than 20 percent and potentially would be considered intermediate combustion turbines. To estimate reductions, the EPA assumed that the number of simple cycle turbines constructed between 2015 and 2022 and the operation of those combustion turbines would continue on an annual basis.[749] For each simple cycle turbine that operated at a capacity greater than 20 percent, the EPA determined the percent reduction in emissions, based on the maximum 12-operating months intermediate load emission rate, that would be required to comply with the final NSPS for intermediate load turbines. The EPA then applied that same percent reduction in emissions to the average operating capacity factor to determine the emission reductions from the NSPS. Using this approach, the EPA estimates that the intermediate load standard will impact approximately a quarter of new simple cycle turbines. The EPA divided the total amount of calculated reductions for intermediate load simple cycle turbines built between 2015 and 2022 and divided that value by 7 (the number of years evaluated) to get estimated annual reductions. This approach results in annual reductions of 31,000 tons of CO_2 as well as 8 tons of NO_X. The emission reductions are projected to result primarily from building additional higher efficiency aeroderivative simple cycle turbines instead of less efficient frame simple cycle turbines. The reduced emissions come from relatively small reductions in the emission rates of the intermediate load aeroderivative simple cycle turbines. This is a snapshot of projected emission reductions from applying the NSPS retroactively to 2022. If more intermediate load simple cycle turbines are built in the future, the emission reductions would be higher than this estimate. Conversely, if fewer intermediate load simple cycles are built, the emission reductions would be lower than the EPA's estimate.

Importantly, the ''highly efficient generation'' which the EPA has determined to be the BSER for new and reconstructed intermediate load combustion turbines and to be the first component BSER for base load stationary combustions, is not the same as the ''heat rate improvements'' (HRI, or ''efficiency improvements'') that the EPA determined to be the BSER for existing coal-fired steam generating EGUs in the ACE Rule. As noted earlier in this document, the EPA has concluded that the suite of HRI in the ACE Rule is not an appropriate BSER for existing coal-fired EGUs. In the EPA's technical judgment, the suite of HRI set forth in the ACE Rule would provide negligible CO_2 reductions at best and, in many cases, may increase CO_2 emissions because of the ''rebound effect,'' which is explained and discussed in section VII.D.4.a.iii of this preamble. Increased CO_2 emissions from the ''rebound effect'' can occur when a coal-fired EGU improves its efficiency (heat rate), which can move the unit up on the dispatch order—resulting in an EGU operating for more hours during the year than it would have without having done the efficiency improvements. There is also the possibility that a more efficient coal-fired EGU could displace a lower emitting generating source, further exacerbating the problem.

Conversely, including ''highly efficient generation'' as a component of the BSER for new and reconstructed does not create this risk of displacing a lower-emitting generating source. A new highly efficient stationary combustion turbine may be dispatched more than it would have been if it were not built as a highly efficient turbine, but it is more likely to displace an existing coal-fired EGU or a less efficient existing stationary combustion turbine. It would be unlikely to displace a renewable generating source.

For base load stationary combustion turbines, ''highly efficient generation'' is the first component of the BSER—with 90 percent capture CCS being the second component of the BSER. This is very similar to the Agency's BSER determination for the NSPS for new fossil fuel-fired steam generating units. In that final rule, the EPA established standards of performance for newly constructed fossil fuel-fired steam generating units based on the performance of a new highly efficient supercritical pulverized coal (SCPC) EGU implementing post-combustion partial CCS technology, which the EPA determined to be the BSER for these sources.[750]

[748] The emission reduction comparison is done assuming the same level of operation. Overall emission impacts would be different if the more efficient combustion turbine operates more then the baseline.

[749] This is a simplified assumption that does not take into account changing market conditions that could change the makeup and operation of new combustion turbines.

[750] See 80 FR 64510 (October 23, 2015).

v. Promotion of the Development and Implementation of Technology

The EPA also considered the potential impact of selecting highly efficient simple cycle generation technology as the BSER for the intermediate load subcategory in promoting the development and implementation of improved control technology. New highly efficient simple cycle turbines are more efficient than the average new simple cycle turbine and a standard based on the performance of the most efficient, best performing simple cycle turbine will promote penetration of the most efficient units throughout the industry. Accordingly, consideration of this factor supports the EPA's proposal to determine this technology to be the BSER.

c. Low-GHG Hydrogen and CCS

The EPA did not propose and is not finalizing either CCS or co-firing low-GHG hydrogen as the first component of the BSER for intermediate load combustion turbines, for the reasons given in sections VIII.F.4.c.iii (CCS) and VIII.F.5 (low-GHG hydrogen).

d. Summary of BSER Determinations

The EPA is finalizing that highly efficient generating technology in combination with the best operating and maintenance practices is the BSER for intermediate load combustion turbines. Specifically, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices is the BSER for intermediate load combustion turbines.

Highly efficient generation qualifies the BSER because it is adequately demonstrated, it can be implemented at reasonable cost, it achieves emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements. The fact that it promotes greater use of advanced technology provides additional support; however, the EPA considers highly efficient generation to the BSER for intermediate load combustion turbines even without taking this factor into account.

3. BSER for Base Load Subcategory—First Component

This section describes the first component of the BSER for newly constructed and reconstructed combustion turbines in the base load subcategory. For combustion turbines in the base load subcategory, the first component of the BSER is the use of high-efficiency combined cycle technology in combination with the best operating and maintenance practices.

a. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the BSER for base load combustion turbines because, as described earlier in this section, it would achieve few GHG emission reductions compared to highly efficient generation.

b. Highly Efficient Generation

i. Adequately Demonstrated

The EPA proposed and is finalizing that highly efficient combined cycle designs are adequately demonstrated because highly efficient combined cycle EGUs have been demonstrated by multiple facilities for decades, and the efficiency improvements of the most efficient designs are incremental in nature and do not change in any significant way how the combustion turbine is operated or maintained. Due to the differences in HRSG efficiencies for smaller combined cycle turbines, the EPA proposed and is finalizing less stringent standards of performance for smaller base load turbines with base load ratings of less than 2,000 MMBtu/h relative to those for larger base load turbines. The levels of efficiency that the EPA is proposing have been achieved by many recently constructed combustion turbines. Therefore, efficient generation technology described in this BSER is commercially available and the standards of performance are achievable.

ii. Costs

For the base load subcategory, the EPA considers the cost of high-efficiency combined cycle EGUs to be reasonable. While the capital costs of a higher efficiency combined cycle EGUs are 1.9 percent higher than standard efficiency combined cycle EGUs, fuel use is 2.6 percent lower.[751] The reduction in fuel costs fully offset the capital costs at capacity factors of 40 percent or greater over the expected 30-year life of the facility. Therefore, a BSER based on the use of high-efficiency combined cycle combustion turbines for base load combustion turbines would have minimal, if any, overall compliance costs since the capital costs would be recovered through reduced fuel costs over the expected 30-year life of the facility.

[751] Cost And Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 4A (October 2022), *https://www.osti.gov/servlets/purl/1893822*.

iii. Non-Air Quality Health and Environmental Impact and Energy Requirements

Use of highly efficient generation reduces all non-air quality health and environmental impacts and energy requirements as compared to use of less efficient generation. Even when operating at the same input-based emissions rate, the more efficient a unit is, the less fuel is required to produce the same level of output; and, as a result, emissions are reduced for all pollutants. The use of highly efficient combustion turbines, compared to the use of less efficient combustion turbines, reduces all pollutants. By the same token, because improved efficiency allows for more electricity generation from the same amount of fuel, it will not have any adverse effects on energy requirements.

Designating highly efficient generation as part of the BSER for new and reconstructed base load combustion turbines will not have significant impacts on the nationwide supply of electricity, electricity prices, or the structure of the electric power sector. On a nationwide basis, the additional costs of the use of highly efficient generation will be small because the technology does not add significant costs and at least some of those costs are offset by reduced fuel costs. In addition, at least some of these new combustion turbines would be expected to incorporate highly efficient generation technology in any event.

iv. Extent of Reductions in CO_2 Emissions

The EPA used a similar approach to estimating emission reductions for base load combustion turbines as intermediate load combustion turbines, except the Agency reviewed recently constructed combined cycle EGUs. As discussed in section VIII.G.1, the EPA determined that the standard of performance reflecting this BSER is 800 lb CO_2/MWh-gross for base load combustion turbines. The Agency assumed all new combined cycle turbines would be impacted by the base load emissions standard. Between the beginning of 2015 and the beginning of 2022, 129 combined cycle turbines, an average of 18 per year, commenced operation. Of those combined cycle turbines, 107 had 12-operating month emissions data. For each of these 107 combined cycle turbines that had a maximum 12-operating month emissions rate greater than 800 lb CO_2/MWh-gross, the EPA determined the reductions that would occur assuming the combined cycle turbine reduced its

emissions rate to 800 lb CO_2/MWh-gross and continued to operate at its average capacity factor. The EPA summed the results and divided by 8 (the number of years evaluated) to estimate the annual GHG reductions that will result from this final rule. The EPA estimates that the base load standard will result in annual reductions of 313,000 tons of CO_2 as well as 23 tons of NO_X. The reductions increase each year and in year 3 the annual reductions would be 939,000 tons of CO_2 and 69 tons of NO_X.

v. Promotion of the Development and Implementation of Technology

The EPA also considered the potential impact of selecting highly efficient generation technology as the BSER in promoting the development and implementation of improved control technology. The highly efficient combustion turbines are more efficient and lower emitting than the average new combustion turbine generation technology. Determining that highly efficient turbines are a component of the BSER will advance penetration of the best performing combustion turbines throughout the industry—and will incentivize manufacturers to offer improved turbines that meet the final standard of performance associated with application of the BSER. Accordingly, consideration of this factor supports the EPA's proposal to determine this technology to be the BSER.

c. Low-GHG Hydrogen and CCS

The EPA did not propose and is not finalizing either CCS or co-firing low-GHG hydrogen as the first component of the BSER for base load combustion turbines, for the reasons given in sections VIII.F.4.c.iii (CCS) and VIII.F.5 (low-GHG hydrogen).

d. Summary of BSER Determinations

The EPA is finalizing that highly efficient generating technology in combination with the best operating and maintenance practices is the BSER for first component of the BSER for base load combustion turbines. The phase-1 standards of performance are based on the application of that technology. Specifically, the use of highly efficient combined cycle technology in combination with best operating and maintenance practices is the first component of the BSER for base load combustion turbines.

Highly efficient generation qualifies as the BSER because it is adequately demonstrated, it can be implemented at reasonable cost, it achieves emission reductions, and it does not have significant adverse non-air quality health or environmental impacts or significant adverse energy requirements. The fact that it promotes greater use of advanced technology provides additional support; however, the EPA considers highly efficient generation to be a component of the BSER for base load combustion turbines even without taking this factor into account.

4. BSER for Base Load Subcategory—Second Component

a. Authority To Promulgate a Multi-Part BSER and Standard of Performance

The EPA's approach of promulgating standards of performance that apply in multiple phases, based on determining the BSER to be a set of controls with multiple components, is consistent with CAA section 111(b). That provision authorizes the EPA to promulgate ''standards of performance,'' CAA section 111(b)(1)(B), defined, in the singular, as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the [BSER].'' CAA section 111(a)(1). CAA section 111(b)(1)(B) further provides, ''[s]tandards of performance . . . shall become effective upon promulgation.'' In this rulemaking, the EPA is determining that the BSER is a set of controls that, depending on the subcategory, include highly efficient generation plus use of CCS. The EPA is determining that affected sources can apply the first component of the BSER—highly efficient generation—by the effective date of the final rule and can apply both the first and second components of the BSER—highly efficient generation in combination with 90 percent CCS—in 2032.

Accordingly, the EPA is finalizing standards of performance that reflect the application of this multi-component BSER and that take the form of standards of performance that affected sources must comply with in two phases. This multi-phase standard of performance ''become[s] effective upon promulgation.'' CAA section 111(b)(1)(B). That is, upon promulgation, affected sources become legally subject to the multi-phase standard of performance and must comply with it by its terms. Specifically, affected sources must comply with the first phase standards, which are based on the application of the first component of the BSER, upon initial startup of the facility. They must comply with the second phase standards, which are based on the application of both the first and second components of the BSER, beginning January 2032.

D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the ''adequately demonstrated'' criterion—even if the controls require some amount of ''lead time,'' which the court has defined as ''the time in which the technology will have to be available.'' [752] The caselaw's interpretation of ''adequately demonstrated'' to accommodate lead time accords with common sense and the practical experience of certain types of controls, discussed below. Consistent with this caselaw, the phased implementation of the standards of performance in this rule ensures that facilities have sufficient lead time for planning and implementation of the use of CCS-based controls necessary to comply with the second phase of the standards, and thereby ensures that the standards are achievable. For further discussion of this point, see section V.C.2.b.iii.

The EPA has promulgated several prior rulemakings under CAA section 111(b) that have similarly provided the regulated sector with lead time to accommodate the availability of technology, which also serve as precedent for the two-phase implementation approach proposed in this rule. See 81 FR 59332 (August 29, 2016) (establishing standards for municipal solid waste landfills with 30-month compliance timeframe for installation of control device, with interim milestones); 80 FR 13672, 13676 (March 16, 2015) (establishing stepped compliance approach to wood heaters standards to permit manufacturers lead time to develop, test, field evaluate and certify current technologies to meet Step 2 emission limits); 78 FR 58416, 58420 (September 23, 2013) (establishing multi-phased compliance deadlines for revised storage vessel standards to permit sufficient time for production of necessary supply of control devices and for trained personnel to perform installation); 77 FR 56422, 56450 (September 12, 2012) (establishing standards for petroleum refineries, with 3-year compliance timeframe for installation of control devices); 71 FR 39154, 39158 (July 11, 2006) (establishing standards for stationary compression ignition internal combustion engines, with 2- to 3-year compliance timeframe and up to 6 years for certain emergency fire pump engines); 70 FR 28606, 28617 (March 18, 2005) (establishing two-phase caps for

[752] See *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

mercury standards of performance from new and existing coal-fired electric utility steam generating units based on timeframe when additional control technologies were projected to be adequately demonstrated).[753] *Cf.* 80 FR 64662, 64743 (October 23, 2015) (establishing interim compliance period to phase in final power sector GHG standards to allow time for planning and investment necessary for implementation activities).[754] In each action, the standards and compliance timelines were effective upon the final rule, with affected facilities required to comply consistent with the phased compliance deadline specified in each action.

It should be noted that the multi-phased implementation of the standards of performance that the EPA is finalizing in this rule, like the delayed or multi-phased standards in prior rules just described, is distinct from the promulgation of revised standards of performance under the 8-year review provision of CAA section 111(b)(1)(B). As discussed in section VIII.F, the EPA has determined that the proposed BSER—highly efficient generation and use of CCS—meet all of the statutory criteria and are adequately demonstrated for the compliance timeframes being finalized. Thus, the second phase of the standard of performance applies to affected facilities that commence construction after May 23, 2023 (the date of the proposal). In contrast, when the EPA later reviews and (if appropriate) revises a standard of performance under the 8-year review provision, then affected sources that commence construction after the date of that proposal of the revised standard of performance will be subject to that standard, but not sources that commenced construction earlier.

Similarly, the multi-phased implementation of the standard of performance that the EPA is including in this rule is also distinct from the promulgation of emission guidelines for existing sources under CAA section 111(d). Emission guidelines only apply to existing sources, which are defined in CAA section 111(a)(6) as ''any stationary source other than a new source.'' Because new sources are defined relative to the proposal of standards pursuant to CAA section 111(b)(1)(B), standards of performance adopted pursuant to emission guidelines will only apply to sources constructed before May 23, 2023, the date of the proposed standards of performance for new sources.

b. BSER for the Intermediate Load Subcategory—Second Component

The EPA proposed that the second component of the BSER for intermediate load combustion turbines was co-firing 30 percent low-GHG hydrogen in 2032. As discussed in section VIII.F.5.b, the EPA is not determining that low-GHG hydrogen qualifies as the BSER at this time. Therefore, the Agency is not finalizing a second component of the BSER for intermediate load combustion turbines.

c. BSER for Base Load Subcategory—Second Component

i. Lower-Emitting Fuels

The EPA did not propose and is not finalizing lower-emitting fuels as the second component of the BSER for intermediate or base load combustion turbines because it would achieve few emission reductions, compared to highly efficient generation without or in combination with the use of CCS.

ii. Highly Efficient Generation

For the reasons described above, the EPA is determining that highly efficient generation in combination with best operating and maintenance practices continues to be a component of the BSER that is reflected in the second phase of the standards of performance for base load combustion turbine EGUs. Highly efficient generation reduces fuel use and, therefore, the amount of CO_2 that must be captured by a CCS system. Since a highly efficient turbine system would produce less flue gas that would need to be treated (compared to a less efficient turbine system), physically smaller carbon capture equipment may be used—potentially reducing capital, fixed, and operating costs.

iii. Hydrogen Co-Firing

The EPA proposed a pathway for the second component of the BSER for base load combustion turbines of co-firing 30 percent low-GHG hydrogen in 2032 increasing to 96 percent low-GHG hydrogen co-firing in 2038. As discussed in section VIII.F.5.b of this preamble, the EPA is not finalizing a determination that low-GHG hydrogen co-firing qualifies as the BSER. Therefore, the Agency is not finalizing a second component low-GHG hydrogen co-firing pathway of the BSER for base load combustion turbines. As the EPA's standard of performance is technology neutral, however, affected sources may comply with it by co-firing hydrogen.

iv. CCS

(A) Overview

In this section of the preamble, the EPA explains its rationale for finalizing that CCS with 90 percent capture is a component of the BSER for new base load combustion turbines. CCS is a control technology that can be applied at the stack of a combustion turbine EGU, achieves substantial reductions in emissions and can capture and permanently sequester at least 90 percent of the CO_2 emitted by combustion turbines. The technology is adequately demonstrated, given that it has been operated on a large scale and is widely applicable to these sources, and there are vast sequestration opportunities across the continental U.S. Additionally, the costs for CCS are reasonable in light of recent technology cost declines and policies including the tax credit under IRC section 45Q. Moreover, the non-air quality health and environmental impacts of CCS can be mitigated, and the energy requirements of CCS are not unreasonably adverse. The EPA's weighing of these factors together provides the basis for finalizing 90 percent capture CCS as a component of BSER for these sources. In addition, this BSER determination aligns with the caselaw, discussed in section V.C.2.h of the preamble, stating that CAA section 111 encourages continued advancement in pollution control technology.

This section incorporates by reference the parts of section VII.C.1.a. of this preamble that discuss the many aspects of CCS that are common to both steam generating units and to new combustion turbines. This includes the discussion of simultaneous demonstration of CO_2 capture, transport, and sequestration discussed at VII.C.1.a.i(A); the discussion of CO_2 capture technology used at coal-fired steam generating units at VII.C.1.a.i(B) (the Agency explains below why that record is also relevant to our BSER analysis for new combustion turbines); the discussion of CO_2 transport at VII.C.1.a.i(C); and the discussion of geologic storage of CO_2 at VII.C.1.a.i(D). And the record supporting that transport and sequestration of CO_2 from coal-fired units is adequately demonstrated and meets the other requirements for BSER applies as well to transport and sequestration of CO_2 from combustion turbines.

The primary differences between using post-combustion capture from a coal combustion flue gas and a natural gas combustion flue gas are associated with the level of CO_2 in the flue gas stream and the levels of other pollutants that must be removed. In coal

[753] *Cf. New Jersey* v. *EPA,* 517 F.3d 574, 583–584 (D.C. Cir. 2008) (vacating rule on other grounds).

[754] *Cf. West Virginia* v. *EPA,* 597 U.S. 697 (2022) (vacating rule on other grounds).

combustion flue gas, the concentration of CO_2 is typically approximately 13 to 15 volume percent, while the concentration of CO_2 from natural gas-fired combined cycle combustion flue gas is approximately 3 to 4 volume percent.[755] Capture of CO_2 at dilute concentrations is more challenging but there are commercially available amine-based solvents that can be used with dilute CO_2 streams to achieve 90 percent capture. In addition, flue gas from a coal-fired steam EGU contains a variety of non-carbonaceous components that must be removed to meet environmental limits (*e.g.,* mercury and other metals, particulate matter (fly ash), and acid gases (including sulfur dioxide (SO_2) and hydrogen chloride and hydrogen fluoride). When amine-based post-combustion carbon capture is used with a coal-fired EGU, the flue gas stream must be further cleaned, sometimes beyond required environmental standards, to avoid the fouling of downstream process equipment and to prevent degradation of the amine solvent. Absent pretreatment of the coal combustion flue gas, the amines can absorb SO_2 and other acid gases to form heat stable salts, thereby degrading the performance of the solvent. Amine solvents can also experience catalytic oxidative degradation in the presence of some metal contaminants. Thermal oxidation of the solvent can also occur but can be mitigated by interstage cooling of the absorber column. Natural gas combustion flue gas typically contains very low (if any) levels of SO_2, acid gases, fly ash, and metals. Therefore, fouling and solvent degradation are less of a concern for carbon capture from natural gas-fired EGUs.

New natural gas-fired combustion turbine EGUs also have the option of using oxy-combustion technology—such as that currently being demonstrated and developed by NET Power. As discussed earlier, the NET Power system uses oxy-combustion (combustion in pure oxygen) of natural gas and a high-pressure supercritical CO_2 working fluid (instead of steam) to produce electricity in a combined cycle turbine configuration. The combustion products are water and high-purity, pipeline-ready CO_2 which is available for sequestration or sale to another industry. The NET Power technology does not involve solvent-based CO_2 separation and capture since pure CO_2 is a product of the process. The NET Power technology is not currently applicable to coal-fired steam generating utility boilers—though it could be utilized with combustion of gasified coal or other solid fossil fuels (*e.g.,* petroleum coke).

For new base load combustion turbines, the EPA proposed that CCS with a 90 percent capture rate, beginning in 2035, meets the BSER criteria. Some commenters agreed with the EPA that CCS for base load combustion turbines satisfies the BSER criteria. Other commenters claimed that CCS is not a suitable BSER for new base load combustion turbines. The EPA disagrees with these commenters.

As with existing coal-fired steam generating units, CCS applied to new combined cycle combustion turbines has three major components: CO_2 capture, transportation, and sequestration/storage. CCS with 90 percent capture has been adequately demonstrated for combined cycle combustion turbines for many of the same reasons described in section VII.C.1.a.i. The Bellingham Energy Center, a natural gas-fired combined cycle combustion turbine in south central Massachusetts, successfully applied post-combustion carbon capture using the Fluor Econamine FG Plus℠ amine-based solvent from 1991–2005 with 85–95 percent CO_2 capture.[756] The plant captured approximately 365 tons of CO_2 per day from a 40 MW slip stream [757] and was ultimately shut down and decommissioned primarily due to rising gas prices.

As discussed in further detail below, additional natural gas-fired combined cycle combustion turbine CCS projects are in the planning stage, which confirms that CCS is becoming accepted across the industry. As discussed above, CCS with 90 percent capture has been demonstrated for coal-fired steam generating units, and that information forms part of the basis for the EPA's determination that CCS with 90 percent capture has been have adequately demonstrated for these combustion turbines. Statements from vendors and the experience of industrial applications of CCS provide further support that post-combustion CCS with 90 percent capture is adequately demonstrated for these combustion turbines.

The EPA's analysis of the transportation and sequestration components of CCS for new base load combustion turbines is similar to its analysis of those components for existing coal-fired steam generating units and, therefore, for much the same reasons, the EPA is determining that each of those components is adequately demonstrated, and that CCS as a whole—including those components when combined with the 90 percent CO_2 capture component—is adequately demonstrated. In addition, new sources may consider access to CO_2 transport and storage sites in determining where to build, and the EPA expects that since this rule was proposed, companies siting new base load combustion turbines have taken into consideration the likelihood of a regulatory regime requiring significant emissions reductions.

The use of CCS at 90 percent capture can be implemented at reasonable cost because it allows affected sources to maximize the benefits of the IRC section 45Q tax credit. Finally, any adverse health and environmental impacts and energy requirements are limited and, in many cases, can be mitigated or avoided. It should also be noted that a determination that CCS is the BSER for these units will promote further use and development of this advanced technology. After balancing these factors, the EPA is determining that utilization of CCS with 90 percent capture for new base load combustion turbine EGUs satisfies the criteria for BSER.

(B) Adequately Demonstrated

The legal test for an adequately demonstrated system, and an achievable standard, has been discussed at length above. (See sections V.C.2.b and VII.C.a.i of this preamble). As previously noted, concepts of adequate demonstration and achievability are closely related: ''[i]t is the *system* which must be adequately demonstrated and the *standard* which must be achievable,'' [758] based on application of the system. An achievable standard means a standard based on the EPA's finding that sufficient evidence exists to reasonably determine that the affected sources in the source category can adopt a specific system of emission reduction to achieve the specified degree of emission limitation. The foregoing sections have shown that CCS, specifically using amine post-combustion CO_2 capture, is adequately demonstrated for existing coal units,

[755] NETL Carbon Dioxide Capture Approaches. *https://netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/capture-approaches.*

[756] Fluor Econamine FG Plus℠ brochure. *https://a.fluor.com/f/1014770/x/a744f915e1/econamine-fg-plus-brochure.pdf.*

[757] ''Commercially Available CO_2 Capture Technology'' Power, (Aug 2009). *https://www.powermag.com/commercially-available-co2-capture-technology/.*

[758] *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (1973).

and that a 90 percent capture standard is achievable.[759]

Pursuant to *Lignite Energy Council* v. *EPA,* the EPA may extrapolate based on data from a particular kind of source to conclude that the technology at issue will also be effective at a similar source.[760] This standard is satisfied in our case, because of the essential ways in which CO_2 capture at coal-fired steam generating units is identical to CO_2 capture at natural gas-fired combined cycle turbines. As detailed in section VII.C.1.a.i(B), amine-based CO_2 capture removes CO_2 from post-combustion flue gas by reaction of the CO_2 with amine solvent. The same technology (*i.e.,* the same solvents and processes) that is employed on coal-fired steam generating units—and that is employed to capture CO_2 from fossil fuel combustion in other industrial processes—can be applied to remove CO_2 from the post-combustion flue gas of natural gas-fired combined cycle EGUs. In fact, the only differences in application of amine-based CO_2 capture on a natural gas-fired combined cycle unit relative to a coal-fired steam generating unit are related to the differences in composition of the respective post-combustion flue gases, and as explained below, these differences do not preclude achieving 90 percent capture from a gas-fired turbine.

First, while coal flue gas contains impurities including SO_2, PM, and trace minerals that can affect the downstream CO_2 process, and thus coal flue gas requires substantial pre-treatment, the post-combustion flue gas of natural gas-fired combustion turbines has few, if any, impurities that would impact the downstream CO_2 capture plant. Where impurities are present, SO_2 in particular can cause solvent degradation, and coal-fired sources without an FGD would likely need to install one. Filterable PM (fly ash) from coal, if not properly managed, can cause fouling and scale to accumulate on downstream blower fans, heat exchangers, and absorber packing material. Further, additional care in the solvent reclamation is necessary to mitigate solvent degradation that could otherwise occur due to the trace elements that can be present in coal. Because the flue gas from natural gas-fired combustion turbines contains few, if any, impurities that would impact downstream CO_2 capture, the flue gas from natural gas-fired combined cycle EGUs is easier to work with for CO_2 capture, and many of the challenges that were faced by earlier commercial scale demonstrations on coal-fired units can be avoided in the application of CCS at natural gas-fired combustion turbines.

Second, the CO_2 concentration of natural gas-fired combined cycle flue gas is lower than that of coal flue gas (approximately 3-to-4 volume percent for natural gas combined cycle EGUs; 13-to-15 volume percent for coal). For solvent-based CO_2 capture, CO_2 concentration is the driving force for mass transfer and the reaction of CO_2 with the solvent. However, flue gases with lower CO_2 concentrations can be readily addressed by the correct sizing and design of the capture equipment—and such considerations have been made in evaluating the BSER here and are reflected in the cost analysis in VII.C.1.a.ii(A) of this preamble. Moreover, as is detailed in the following sections of the preamble, amine-based CO_2 capture has been shown to be effective at removal of CO_2 from the flue gas of natural gas-fired combined cycle EGUs. In fact, there is not a technical limit to removal of CO_2 from flue gases with low CO_2 concentrations—the EPA notes that amine solvents have been shown to be able to remove CO_2 to concentrations that are less than the concentration of CO_2 in the atmosphere.

Considering these factors, the evidence that underlies the EPA's determination that amine post-combustion CO_2 capture is adequately demonstrated, and that a 90 percent capture standard is achievable, at coal-fired steam generating units, also applies to natural gas-fired combined cycle EGUs. Where differences exist, due to differences in flue gas composition, CCS at natural gas-fired combined cycle combustion turbines will in general face fewer challenges than CCS at coal-fired steam generators.[761] Moreover, in addition to the evidence outlined above, the following sections provide additional information specific to, including examples of, anime-based capture at natural gas-fired combined cycle EGUs. For these reasons, the EPA has determined that CCS at 90 percent capture is adequately demonstrated for natural gas fired combined cycle EGUs.

(1) CO_2 Capture for Combined Cycle Combustion Turbines

As discussed in the preceding, new stationary combustion turbines can use amine-based post-combustion capture. Additionally, new stationary combustion turbines may also utilize oxy-combustion, which uses a purified oxygen stream from an air separation unit (often diluted with recycled CO_2 to control the flame temperature) to combust the fuel and produce a nearly pure stream of CO_2 in the flue gas, as opposed to combustion with oxygen in air which contains 80 percent nitrogen. Currently available post-combustion amine-based CO_2 capture systems require that the flue gas be cooled prior to entering the capture equipment. This holds true for the exhaust from either a coal-fired utility boiler or from a combustion turbine. The most energy efficient way to cool the flue gas stream is to use a HRSG—which, as explained above, is an integral component of a combined cycle turbine system—to generate additional useful output.[762]

CO_2 capture has been successfully applied to an existing combined cycle turbine and several other projects are in development, as discussed immediately below.

(a) CCS on Combined Cycle EGUs

The most prominent example of the use of carbon capture technology on a natural gas-fired combined cycle turbine EGU was at the 386 MW Bellingham Cogeneration Facility in Bellingham, Massachusetts. The plant used Fluor's Econamine FG Plus^{SM} amine-based CO_2 capture system with a capture capacity of 360 tons of CO_2 per day. The system was used to produce food-grade CO_2 and was in continuous commercial operation from 1991 to 2005 (14 years). The capture system was able to continuously capture 85–95 percent of the CO_2 that would have otherwise been emitted from the flue gas of a 40 MW slip stream.[763] The natural gas combustion flue gas at the facility contained 3.5 volume percent CO_2 and 13–14 volume percent oxygen. As mentioned earlier, the flue gas from a coal combustion flue gas stream has a typical CO_2 concentration of approximately 15 volume percent and more dilute CO_2 stream are more challenging to separate and capture. Just before the CO_2 capture system was shut

[759] The EPA uses the two phrases (i) BSER is CCS with 90 percent capture and (ii) CCS with 90 percent capture is achievable, or similar phrases, interchangeably.

[760] *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999).

[761] Many of the challenges faced by Boundary Dam Unit 3—which proved to be solvable—were caused by the impurities, including fly ash, SO_2, and trace contaminants in coal-fired post-combustion flue gas—which do not occur in the natural gas post-combustion flue gas. As a result, for CO_2 capture for natural gas combustion, flue gas handling is simpler, solvent degradation is easier to prevent, and fewer redundancies may be necessary for various components (*e.g.,* heat exchangers).

[762] The EPA proposed that because the BSER for non-base load combustion turbines was simple cycle technology, CCS was not applicable.

[763] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. *https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.*

down in 2005 (due to high natural gas price), the system had logged more than 120,000 hours of CO_2 capture [764] and had a 98.5 percent on-stream (availability) factor.[765]

The Fluor Econamine FG Plus[SM] is a propriety carbon capture solution with more than 30 licensed plants and more than 30 years of operation. This technology uses a proprietary solvent to capture CO_2 from post-combustion sources. The process is well suited to capture CO_2 from large, single-point emission sources such as power plants or refineries, including large facilities with CO_2 capture capacities greater than 10,000 tons per day.[766] On February 6, 2024, Fluor Corporation announced that Chevron New Energies plans to use the Econamine FG Plus[SM] carbon capture technology to reduce CO_2 emissions at Chevron's Eastridge Cogeneration combustion turbine facility in Kern County, California. When installed, Fluor's carbon capture solution is expected to reduce the Eastridge Cogeneration facility's carbon emissions by approximately 95 percent.[767]

Moreover, recently, CO_2 capture technology has been operated on NGCC post-combustion flue gas at the Technology Centre Mongstad (TCM) in Norway.[768] TCM can treat a 12 MWe flue gas stream from a natural gas combined cycle cogeneration plant at Mongstad power station. Many different solvents have been operated at TCM including MHI's KS–21™ solvent,[769] achieving capture rates of over 98 percent.

Additionally, in Scotland, the proposed 900 MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. MHI is developing a FEED for the power plant and capture facility.[770] It is anticipated that the power plant will be operational by the end of the 2020s and will have the potential to capture 90 percent of the CO_2 emitting from the combined cycle facility and sequester up to 1.5 million metric tons of CO_2 annually. A storage site being developed 62 miles off the Scottish North Sea coast will serve as a destination for the captured CO_2.[771] [772]

Furthermore, the Global CCS Centre is tracking other international CCS on combustion turbine projects that are in on-going stages of development.[773]

(b) NET Power Cycle

In addition, there are several planned projects using NET Power's Allam-Fetvedt Cycle.[774] The Allam-Fetvedt Cycle is a proprietary process for producing electricity that combusts a fuel with purified oxygen (diluted with recycled CO_2 to control flame temperature) and uses supercritical CO_2 as the working fluid instead of water/steam. This cycle is designed to achieve thermal efficiencies of up to 59 percent.[775] Potential advantages of this cycle are that it emits no NO_X and produces a stream of high-purity CO_2 [776] that can be delivered by pipeline to a storage or sequestration site without extensive processing. A 50 MW (thermal) test facility in La Porte, Texas was completed in 2018 and has since accumulated over 1,500 hours of runtime. There are several announced NET Power commercial projects proposing to use the Allam-Fetvedt Cycle. These include the 280 MW Broadwing Clean Energy Complex in Illinois, and several international projects.

In Scotland, the proposed 900 MW Peterhead Power Station combined cycle EGU with CCS is in the planning stages of development. MHI is developing a FEED for the power plant and capture facility.[777] It is anticipated that the power plant will be operational by the end of the 2020s and will have the potential to capture 90 percent of the CO_2 emitting from the combined cycle facility and sequester up to 1.5 million metric tons of CO_2 annually. A storage site being developed 62 miles off the Scottish North Sea coast will serve as a destination for the captured CO_2.[778] [779]

(c) Coal-Fired Steam Generating Units

As detailed in section VII.C.1.a, CCS has been demonstrated on coal-fired power plants, which provides further support that CCS on base load combined cycle units is adequately demonstrated. Further, 90 percent capture is expected to be, in some ways, more straightforward to achieve for natural gas-fired combined cycle combustion turbines than for coal-fired steam generators. Many of the challenges faced by Boundary Dam Unit 3—which proved to be solvable—were caused by the impurities, including fly ash, SO_2, and trace contaminants in coal-fired post-combustion flue gas. Such impurities naturally occur in coal (sulfur and trace contaminants) or are a natural result of combusting coal (fly ash), but not in natural gas, and thus they do not appear in the natural gas post-combustion flue gas. As a result, for CO_2 capture for natural gas combustion, flue gas handling is simpler, solvent degradation is easier to prevent, and fewer redundancies may be necessary for various components (*e.g.,* heat exchangers).

(d) Other Industry

As discussed in section VII.C.1.a.i.(A)(1) of this preamble, CCS installations in other industries support that capture equipment can achieve 90 percent capture of CO_2 from natural gas-fired base load combined cycle combustion turbines.

(e) EPAct05-Assisted CO_2 Capture Projects at Stationary Combustion Turbines

As for steam generating units, EPAct05-assisted CO_2 capture projects on stationary combustion turbines corroborate that CO_2 capture on gas combustion turbines is adequately demonstrated. Several CCS projects with at least 90 percent capture at commercial-scale combined cycle turbines are in the planning stages. These projects support that CCS with at least 90 percent capture for these units is the industry standard and support the EPA's determination that CCS is adequately demonstrated.

CCS is planned for the existing 550 MW natural gas-fired combined cycle (two combustion turbines) at the Sutter Energy Center in Yuba City, California.[780] The Sutter

[764] *https://boereport.com/2022/08/16/fluor/.*

[765] ''Technologies for CCS on Natural Gas Power Systems'' Dr. Satish Reddy presentation to USEA, April 2014, *https://usea.org/sites/default/files/event-/Reddy%20USEA%20Presentation%202014.pptx.*

[766] *https://www.fluor.com/market-reach/industries/energy-transition/carbon-capture.*

[767] *https://newsroom.fluor.com/news-releases/news-details/2024/Fluors-Econamine-FG-PlusSM-Carbon-Capture-Technology-Selected-to-Reduce-CO2-Emissions-at-Chevron-Facility/default.aspx.*

[768] *https://netl.doe.gov/carbon-capture/power-generation.*

[769] Mitsubishi Heavy Industries, ''Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New KS–21™ Solvent for CO_2 Capture,'' *https://www.mhi.com/news/211019.html.*

[770] MHI and MHIENG Awarded FEED Contract. *https://www.mhi.com/news/22083001.html.*

[771] Buli, N. (2021, May 10). SSE, Equinor plan new gas power plant with carbon capture in Scotland. *Reuters. https://www.reuters.com/business/sustainable-business/sse-equinor-plan-new-gas-power-plant-with-carbon-capture-scotland-2021-05-11/.*

[772] Acorn CCS granted North Sea storage licenses. September 18, 2023. *https://www.ogj.com/energy-transition/article/14299094/acorn-granted-licenses-for-co2-storage.*

[773] *https://status23.globalccsinstitute.com/.*

[774] The NET Power Cycle was formerly referred to as the Allam-Fetvedt cycle. *https://netpower.com/technology/.*

[775] Yellen, D. (2020, May 25). Allam Cycle carbon capture gas plants: 11 percent more efficient, all CO_2 captured. *Energy Post. https://energypost.eu/allam-cycle-carbon-capture-gas-plants-11-more-efficient-all-co2-captured/.*

[776] This allows for capture of over 97 percent of the CO_2 emissions. *www.netpower.com.*

[780] Calpine Sutter Decarbonization Project, May 17, 2023. *https://www.smud.org/en/Corporate/*

Continued

Decarbonization project will use ION Clean Energy's amine-based solvent technology at a capture rate of 95 percent or more. The project expects to complete a FEED study in 2024 and, prior to being selected by DOE for funding award negotiation, planned commercial operation in 2027. Sutter Decarbonization is one of the projects selected by DOE for funding as part of OCED's Carbon Capture Demonstration Projects program.[781]

The CO_2 capture project at the Deer Park Energy Center in Deer Park, Texas will be designed to capture 95 percent or more of the flue gas from the five combustion turbines at the 1,200 MW natural gas-fired combined cycle power plant, using technology from Shell CANSOLV.[782] The CO_2 capture project already has an air permit issued for the project, which includes a reduction in the allowable emission limits for NO_X from four of the combustion turbines.[783] The CO_2 capture facility will include two quencher columns, two absorber columns, and one stripping column.

The Baytown Energy Center in Baytown, Texas is an existing natural gas-fired combined cycle cogeneration facility providing heat and power to a nearby industrial facility, while distributing additional electricity to the grid. CCS using Shell's CANSOLV solvent is planned for the equivalent of two of the three combustion turbines at the 896 MW natural gas-fired combined cycle power plant, with a capture rate of 95 percent. The CO_2 capture facility at Baytown Energy Center also has an air permit in place, and the permit application provides some details on the process design.[784] The CO_2 capture facility will include two quencher columns, two absorber columns, and one stripping column. To mitigate NO_X emissions, the operation of the SCR systems for the combustion turbines will be adjusted to meet lower NO_X allowable limits—adjustments may include increasing ammonia flow, more frequent SCR repacking and head cleaning, and, possibly, optimization of the ammonia distribution system. The Baytown CO_2 capture project is one of the projects selected by DOE for funding as part of OCED's Carbon Capture Demonstration Projects program.[785] Captured CO_2 will be transported and stored at sites along the U.S. Gulf Coast.

An 1,800 MW natural gas-fired combustion turbine that will be constructed in West Virginia and will utilize CCS has been announced. The project is planned to begin operation later this decade.[786]

There are numerous other EPAct05-assisted projects related to natural gas-fired combined cycle turbines including the following.[787] [788] [789] [790] [791] These projects provide corroborating evidence that capture of at least 90 percent is accepted within the industry.

- General Electric (GE) (Bucks, Alabama) was awarded $5,771,670 to retrofit a combined cycle turbine with CCS technology to capture 95 percent of CO_2 and is targeting commercial deployment by 2030.
- Wood Environmental & Infrastructure Solutions (Blue Bell, Pennsylvania) was awarded $4,000,000 to complete an engineering design study for CO_2 capture at the Shell Chemicals Complex. The aim is to reduce CO_2 emissions by 95 percent using post-combustion technology to capture CO_2 from several plants, including an onsite natural gas CHP plant.
- General Electric Company, GE Research (Niskayuna, New York) was awarded $1,499,992 to develop a design to capture 95 percent of CO_2 from combined cycle turbine flue gas with the potential to reduce electricity costs by at least 15 percent.
- SRI International (Menlo Park, California) was awarded $1,499,759 to design, build, and test a technology that can capture at least 95 percent of CO_2 while demonstrating a 20 percent cost reduction compared to existing combined cycle turbine carbon capture.
- CORMETECH, Inc. (Charlotte, North Carolina) was awarded $2,500,000 to further develop, optimize, and test a new, lower-cost technology to capture CO_2 from combined cycle turbine flue gas and improve scalability to large, combined cycle turbines.
- TDA Research, Inc. (Wheat Ridge, Colorado) was awarded $2,500,000 to build and test a post-combustion capture process to improve the performance of combined cycle turbine flue gas CO_2 capture.
- GE Gas Power (Schenectady, New York) was awarded $5,771,670 to perform an engineering design study to incorporate a 95 percent CO_2 capture solution for an existing combined cycle turbine site while providing lower costs and scalability to other sites.
- Electric Power Research Institute (EPRI) (Palo Alto, California) was awarded $5,842,517 to complete a study to retrofit a 700 MWe combined cycle turbine with a carbon capture system to capture 95 percent of CO_2.
- Gas Technology Institute (Des Plaines, Illinois) was awarded $1,000,000 to develop membrane technology capable of capturing more than 97 percent of combined cycle turbine CO_2 flue gas and demonstrate upwards of 40 percent reduction in costs.
- RTI International (Research Triangle Park, North Carolina) was awarded $1,000,000 to test a novel non-aqueous solvent technology aimed at demonstrating 97 percent capture efficiency from simulated combined cycle turbine flue gas.
- Tampa Electric Company (Tampa, Florida) was awarded $5,588,173 to conduct a study retrofitting Polk Power Station with post-combustion CO_2 capture technology aiming to achieve a 95 percent capture rate.

There are also several announced NET Power Allam-Fetvedt Cycle based CO_2 capture projects that are EPAct05-assisted. These include the 280 MW Coyote Clean Power Project on the Southern Ute Indian Reservation in

Environmental-Leadership/2030-Clean-Energy-Vision/CEV-Landing-Pages/Calpine-presentation.

[781] Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

[782] Calpine Carbon Capture. *https://calpinecarboncapture.com/wp-content/uploads/2023/05/Calpine-Deer-Park-English.pdf.*

[783] Deer Park Energy Center TCEQ Records Online Primary ID 171713.

[784] Baytown Energy Center Air Permit TCEQ Records Online Primary ID 172517.

[785] Carbon Capture Demonstration Projects Selections for Award Negotiations. *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

[786] Competitive Power Ventures (2022). *Multi-Billion Dollar Combined Cycle Natural Gas Power Station with Carbon Capture Announced in West Virginia.* Press Release. September 16, 2022. *https://www.cpv.com/2022/09/16/multi-billion-dollar-combined-cycle-natural-gas-power-station-with-carbon-capture-announced-in-west-virginia/.*

[787] General Electric (GE) (2022). *U.S. Department of Energy Awards $5.7 Million for GE-Led Carbon Capture Technology Integration Project Targeting to Achieve 95% Reduction of Carbon Emissions.* Press Release. February 15, 2022. *https://www.ge.com/news/press-releases/us-department-of-energy-awards-57-million-for-ge-led-carbon-capture-technology.*

[788] Larson, A. (2022). *GE-Led Carbon Capture Project at Southern Company Site Gets DOE Funding.* Power. *https://www.powermag.com/ge-led-carbon-capture-project-at-southern-company-site-gets-doe-funding/.*

[789] U.S. Department of Energy (DOE) (2021). *DOE Invests $45 Million to Decarbonize the Natural Gas Power and Industrial Sectors Using Carbon Capture and Storage.* October 6, 2021. *https://www.energy.gov/articles/doe-invests-45-million-decarbonize-natural-gas-power-and-industrial-sectors-using-carbon.*

[790] DOE (2022). *Additional Selections for Funding Opportunity Announcement 2515.* Office of Fossil Energy and Carbon Management. *https://www.energy.gov/fecm/additional-selections-funding-opportunity-announcement-2515.*

[791] DOE (2019). *FOA 2058: Front-End Engineering Design (FEED) Studies for Carbon Capture Systems on Coal and Natural Gas Power Plants.* Office of Fossil Energy and Carbon Management. *https://www.energy.gov/fecm/foa-2058-front-end-engineering-design-feed-studies-carbon-capture-systems-coal-and-natural-gas.*

Colorado and a 300 MW project located near Occidental's Permian Basin operations close to Odessa, Texas. Commercial operation of the facility near Odessa, Texas is expected in 2028.

(f) Range of Conditions

The composition of natural gas combined cycle post-combustion flue gas is relatively uniform as the level of impurities is, in general, low. There may be some difference in NO_X emissions, but considering the sources are new, it is likely that they will be installed with SCR, resulting in uniform NO_X concentrations in the flue gas. The EPA notes that some natural gas combined cycle units applying CO_2 capture may use exhaust gas recirculation to increase the concentration of CO_2 in the flue gas—this produces a higher concentration of CO_2 in the flue gas. For those sources that apply that approach, the CO_2 capture system can be scaled smaller, reducing overall costs. Considering these factors, the EPA concludes that there are not substantial differences in flue gas conditions for natural gas combined cycle units, and the small differences that could exist would not adversely impact the operation of the CO_2 capture equipment.

As detailed in section VII.C.1.a.i(B)(7), single trains of CO_2 capture facilities have turndown capabilities of 50 percent. Effective turndown to 25 percent of throughputs can be achieved by using 2 trains of capture equipment. CO_2 capture rates have also been shown to be higher at lower throughputs. Moreover, during off-peak hours when electricity prices are lower, additional lean solvent can be produced and held in reserve, so that during high-demand hours, the auxiliary demands to the capture plant stripping column reboiler be reduced. Considering these factors, the capture rate would not be affected by load following operation, and the operation of the combustion turbine would not be limited by turndown capabilities of the capture equipment. As detailed in preceding sections, simple cycle combustion turbines cycle frequently, and have a number of startups and shutdowns per year. However, combined cycle units cycle less frequently and have fewer startups and shutdowns per year. Startups of combined cycle units are faster than coal-fired steam generating units described in section VII.C.1.a.i(B)(7) of the preamble. Cold startups of combined cycle units typically take not more than 3 hours (hot startups are faster), and shutdown takes less than 1 hour. During startup, heat input to the unit is lower to slowly raise the temperature of the HRSG.

Importantly, natural gas post-combustion flue gas does not require the same pretreatment as coal post-combustion flue gas. Therefore, amine solvents are able to capture CO_2 as soon as the flue gas contacts the lean solvent, and startup does not have to wait for operation of other emission controls. Furthermore, there are several different process strategies that can be employed to enable capture during cold startup.[792] [793] These include using an additional reserve of lean solvent (solvent without absorbed CO_2), dedicated heat storage for reboiler preheating, and fast starting steam cycle technologies or high-pressure bypass extraction. Each of these three options has been modeled to show that 95 percent capture rates can be achieved during startup. The first option simply uses a reserve of lean solvent during startup so that capture can occur without needing to wait for the stripping column reboiler to heat up. For hot starts, the startup time of the NGCC is faster, and since the reboiler is already warm, the capture plant can begin operating faster. Shutdowns are short, and high capture efficiencies can be maintained.

Considering that startup and shutdown for natural gas combined cycle units is fast, startups are relatively few, and simple process strategies can be employed so that high capture efficiencies can be achieved during startup, the EPA has concluded that startup and shutdown do not adversely impact the achievable CO_2 capture rate.

Considering the preceding information, the EPA has determined that 90 percent capture is achievable over long periods (*i.e.,* 12-month rolling averages) for base load combustion turbines for all relevant flue gas conditions, variable load, and startup and shutdown.

(g) Summary of Evidence Supporting BSER Determination Without EPAct05-Aassisted Projects

As noted above, under the EPA's interpretation of the EPAct05 provisions, the EPA may not rely on capture projects that received assistance under EPAct05 as the sole basis for a determination of adequate demonstration, but the EPA may rely on those projects to support or corroborate other information that supports such a determination. The information described above that supports the EPA's determination that 90 percent CO_2 capture from natural gas-fired combustion turbines is adequately demonstrated, without consideration of the EPAct05-assisted projects, includes (i) the information concerning coal-fired steam generating units listed in VII.C.1.a.i.(B)(9) [794] (other than the information concerning EPAct05-assisted coal-fired unit projects and the information concerning natural gas-fired combustion turbines); (ii) the information that a 90 percent capture standard is achievable at coal-fired steam generating units, also applies to natural gas-fired combined cycle EGUs (*i.e.,* all the information in VIII.F.4.c.iv.(B) (before (1)) and (1) (before (a)); (iii) the information concerning CCS on combined cycle EGUs (*i.e.,* all the information in VIII.F.4.c.iv.(B)(1)(a)); and (iv) the information concerning Net Power (*i.e.,* all the information in VIII.F.4.c.iv.(B)(1)(b)). All this information by itself is sufficient to support the EPA's determination that 90 percent CO_2 capture from coal-fired steam generating units is adequately demonstrated. Substantial additional information from EPAct05-assisted projects, as described in section VIII.F.4.c.iv.(B)(1)(e), provides additional support and confirms that 90 percent CO_2 capture from natural gas-fired combustion turbines is adequately demonstrated.

(2) Transport of CO_2

In section VII.C.1.a.i.(C) of this document, the EPA described its rationale for finalizing a determination that CO_2 transport by pipelines as a component of CCS is adequately demonstrated for use of CCS with existing steam generating EGUs. The Agency's rationale for finalizing the same determination—that CO_2 transport by pipelines as a component of CCS is adequately demonstrated for CCS use with new combustion turbine EGUs—is much the same as that described in section VII.C.1.a.i.(C). As discussed in

[792] *https://ieaghg.org/ccs-resources/blog/new-ieaghg-report-2022-08-start-up-and-shutdown-protocol-for-power-stations-with-co2-capture.*

[793] *https://assets.publishing.service.gov.uk/media/5f95432ad3bf7f35f26127d2/start-up-shut-down-times-power-ccus-main-report.pdf.*

[794] Specifically, this includes the information concerning Boundary Dam, coupled with engineering analysis concerning key improvements that can be implemented in future CCS deployments during initial design and construction (*i.e.,* all the information in section VII.C.1.a.i.(B)(1)(a) and the information concerning Boundary Dam in section VII.C.1.a.i.(B)(1)(b)); (ii) the information concerning other coal-fired demonstrations, including the Argus Cogeneration Plant and AES's Warrior Run (*i.e.,* all the information concerning those sources in section VII.C.1.a.i.(B)(1)(a)); (iii) the information concerning industrial applications of CCS (*i.e.,* all the information in section VII.C.1.a.i.(A)(1); and (iv) the information concerning CO_2 capture technology vendor statements (*i.e.,* all the information in VII.C.1.a.i.(B)(3)).

section VII.C.1.a.i.(C) of this preamble, CO_2 pipelines are available and their network is expanding in the U.S., and the safety of existing and new supercritical CO_2 pipelines is comprehensively regulated by PHMSA.[795] A new combustion turbine may also be co-located with a storage site, so that minimal transport of the CO_2 is required.

Pipeline transport of CO_2 captured from newly constructed or reconstructed natural gas-fired combustion turbine EGUs meets the BSER requirements based on the same evidence, and for the same reasons, as does pipeline transport of CO_2 captured from existing coal-fired steam generating EGUs, as described in section VII.C.1.a.i.(C) of this preamble. This is because the CO_2 that is captured from a natural gas-fired turbine, compressed, and delivered into a pipeline is indistinguishable from the CO_2 that is captured from an existing coal-fired steam generating unit. Accordingly, all the evidence and explanation in section VII.C.1.a.i.(C) of this preamble that it is adequately demonstrated, cost-effective, and consistent with the other BSER factors for an existing coal-fired steam generating unit to construct a lateral pipeline from its facility to a sequestration site applies to new natural gas-fired turbines. This includes the history of CO_2 pipeline build-out (VII.C.1.a.i.(C)(1)), the recent examples of new pipelines (VII.C.1.a.i.(C)(1)(b)), EPAct05-assisted CO_2 pipelines for CCS (VII.C.1.a.i.(C)(1)(c)), the network of existing and planned CO_2 trunklines (VII.C.1.a.i.(C)(1)(d)), permitting and rights of way considerations (VII.C.1.a.i.(C)(2)), and considerations of the security of CO_2 transport, including PHMSA requirements (VII.C.1.a.i.(C)(3)).

The only difference between pipeline transport for the coal-fired steam generation and the gas-fired turbines is that the coal-fired units are already in existence and, as a result, the location and length of their pipelines, as needed to transport their CO_2 to nearby sequestration, is already known, whereas new gas-fired turbines are not yet sited. We discuss the implications for new gas-fired turbines in the next section.

[795] PHMSA additionally initiated a rulemaking in 2022 to develop and implement new measures to strengthen its safety oversight of CO_2 pipelines following investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020. For more information, see: *https://www.phmsa.dot.gov/news/phmsa-announces-new-safety-measures-protect-americans-carbon-dioxide-pipeline-failures.*

(3) Geologic Sequestration of CO_2

In section VII.C.1.a.i.(D) of this document, the EPA described its rationale for finalizing a determination that geologic sequestration (*i.e.,* the long-term containment of a CO_2 stream in subsurface geologic formations) is adequately demonstrated as a component of the use of CCS with existing coal-fired steam generating EGUs. Similar to the previous discussion regarding CO_2 transport, the Agency's rationale for finalizing a determination that geologic sequestration is adequately demonstrated as a component of the use of CCS with new combustion turbine EGUs is the same as described in VII.C.1.a.i.(D) for existing coal-fired steam generating EGUs. The storage/sequestration sites used to store captured CO_2 from existing coal-fired EGUs could also be used to store captured CO_2 from newly constructed or reconstructed combustion turbine EGUs. All of the considerations and challenges associated with developing geologic storage sites for existing sources are also considerations and challenges associated with developing such sites for newly constructed or reconstructed sources.

(a) In General

Geologic sequestration (*i.e.,* the long-term containment of a CO_2 stream in subsurface geologic formations) is well proven. Deep saline formations, which may be evaluated and developed for CO_2 sequestration are broadly available throughout the U.S. Geologic sequestration requires a demonstrated understanding of the processes that affect the fate of CO_2 in the subsurface. As discussed in section VII.C.1.a.i.(D) of this preamble, there have been numerous instances of geologic sequestration in the U.S. and overseas, and the U.S. has developed a detailed set of regulatory requirements to ensure the security of sequestered CO_2. This regulatory framework includes the UIC well regulations, which are under the authority of the SDWA, and the GHGRP, under the authority of the CAA.

Geologic settings which may be suitable for geologic sequestration of CO_2 are widespread and available throughout the U.S. Through an availability analysis of sequestration potential in the U.S. based on resources from the DOE, the USGS, and the EPA, the EPA found that there are 43 states with access to, or are within 100 km from, onshore or offshore storage in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs.

All of the evidence and explanation that geological sequestration of CO_2 is adequately demonstrated and meets the other BSER factors that the EPA described with respect to sequestration of CO_2 from existing coal-fired steam generating units in section VII.C.1.a.i.(D) of this preamble apply with respect to CO_2 from new natural gas-fired combustion turbines. Sequestration is broadly available (VII.C.1.a.i.(D)(1)(a)). It is adequately demonstrated, with many examples of projects successfully injecting and containing CO_2 in the subsurface (VII.C.1.a.i.(D)(2)). It provides secure storage, with a detailed set of regulatory requirements to ensure the security of sequestered CO_2, including the UIC well regulations pursuant to SDWA authority, and the GHGRP pursuant to CAA authority (VII.C.1.a.i.(D)(4)). The EPA has the experience to properly regulate and review permits for UIC Class VI injection wells, has made considerable improvements to its permitting process to expedite permitting decisions, and has granted several states primacy to issue permits, and is supporting that state permitting (VII.C.1.a.i.(D)(5)).

(b) New Natural Gas-Fired Combustion Turbines

As discussed in section VII.C.1.a.i.(D)(1), deep saline formations that may be considered for use in geologic sequestration (or storage) are common in the continental United States. In addition, there are numerous unmineable coal seams and depleted oil and gas reserves throughout the country that could potentially be utilized as sequestration sites. The DOE estimates that areas of the U.S. with appropriate geology have a sequestration potential of at least 2,400 billion to over 21,000 billion metric tons of CO_2 in deep saline formations, unmineable coal seams, and oil and gas reservoirs. The EPA's scoping assessment found that at least 37 states have geologic characteristics that are amenable to deep saline sequestration and identified an additional 6 states are within 100 kilometers of potentially amenable deep saline formations in either onshore or offshore locations. In terms of land area, 80 percent of the continental U.S. is within 100 km of deep saline formations.[796] While the EPA's geographic availability analyses focus on deep saline formations, other geologic formations such as unmineable coal seams or depleted oil and gas

[796] For additional information on CO_2 transportation and geologic sequestration availability, please see EPA's final TSD, *GHG Mitigation Measures for Steam Generating Units.*

reservoirs represent potential additional CO_2 storage options. Therefore, we expect that the vast majority of new base load combustion turbine EGUs could be sited within 100 km of a sequestration site.

While the potential for some type of sequestration exists in large swaths of the continental U.S., we recognize that there are a few states that do not have geologic conditions suitable for geologic sequestration within or near their borders. If an area does not have a suitable geologic sequestration site, then a utility or project developer seeking to build a new combustion turbine EGU for base load generation has two options—either (1) the new EGU may be located near the electricity demand and the CO_2 transported via a CO_2 pipeline to a geologic sequestration site, or (2) the new EGU may be located closer to a geologic sequestration site and the electricity delivered to customers through transmission lines. Regarding option 1, as discussed in VII.C.1.a.i(C), the EPA believes that both new and existing EGUs are capable of constructing CO_2 pipelines as needed. With regard to option 2, we expect that this option may be preferred for projects where a CO_2 pipeline of substantial length would be required to reach the sequestration site. However, we note that for new base load combustion turbine EGUs, project developers have flexibility with regard to siting such that they can balance whether to site a new unit closer to a potential geologic sequestration site or closer to a load area depending on their specific needs.

Electricity demand in areas that may not have geologic sequestration sites may be served by gas-fired EGUs that are built in areas with geologic sequestration, and the generated electricity can be delivered through transmission lines to the load areas through ''gas-by-wire.'' An analogous approach, known as ''coal-by-wire'' has long been used in the electricity sector for coal-fired EGUs because siting a coal-fired EGU near a coal mine and transmitting the generated electricity long distances to the load area is sometimes less expensive than siting the coal EGU near the load area and shipping the coal long distances. The same principle may apply to new base load combustion turbine EGUs such that it may be more practicable for an project developer to site a new base load combustion turbine EGU in a location in close proximity to a geologic sequestration site and to deliver the electricity generated through transmission lines to the load area rather than siting the new gas-fired combustion turbine EGU near the load area and building a lengthy pipeline to the geologic sequestration site.

Gas-by-wire and coal-by-wire are possible due to the electricity grid's extensive high voltage transmission networks that enable electricity to be transmitted over long distances. See the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units,* which is available in the rulemaking docket for this action. In many of the areas without reasonable access to geologic sequestration, utilities, electric cooperatives, and municipalities have a history of joint ownership of electricity generation outside the region or contracting with electricity generation in outside areas to meet demand. Some of the areas are in Regional Transmission Organizations (RTOs),[797] which engage in planning as well as balancing supply and demand in real time throughout the RTO's territory. Accordingly, generating resources in one part of the RTO can serve load in other parts of the RTO, as well as load outside of the RTO.

In the coal context, there are many examples of where coal-fired power generation in one state has been used to supply electricity in other states. For example, the Prairie State Generating Plant, a 2-unit 1,600 MW coal-fired power plant in Illinois that is currently considering retrofitting with CCS, serves load in eight different states from the Midwest to the mid-Atlantic.[798] The Intermountain Power Project, a coal-fired plant located in Delta, Utah, that is converting to co-fire hydrogen and natural gas, serves customers in both Utah and California.[799] Additionally, historically nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah. Further, Idaho Power, which serves customers in Idaho and eastern Oregon has met demand in part from power generating at coal-fired power plants located in Wyoming and Nevada. This same concept of siting generation in one location to serve demand in another area and using existing transmission infrastructure to do so could similarly be applied to gas-fired combustion turbine power plants, and, in fact, there are examples of gas-fired combustion turbine EGUs serving demand more than 100 km away from where they are sited. For example, Portland General Electric's Carty Generating Station, a 436–MW NGCC unit located in Boardman, Oregon[800] serves demand in Portland, Oregon,[801] which is approximately 270 km away from the source.

In the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units,* we explore in detail the potential for gas-by-wire and the ability of demand in areas without geologic sequestration potential to be served by gas generation located in areas that have access to geologic sequestration. As discussed in the memorandum, the vast majority of the United States is within 100 km of an area with geologic sequestration potential. A review of our scoping assessment indicates that there are limited areas of the country that are not within 100 km of a potential deep saline sequestration formation (although some of these areas may be within 100 km of an unmineable coal seam or depleted oil and gas reservoir that could potentially serve as a sequestration site). In many instances, these areas include areas with low population density, areas that are already served by transmission lines that could deliver gas-by-wire, and/or include areas that have made policy or other decisions not to pursue a resource mix that includes new NGCC due to state renewable portfolio standards or for other reasons.

In many of these areas, utilities, electric cooperatives, and municipalities have a history of obtaining electricity from generation in outside areas to meet demand. Some of the relevant areas are in an RTO or ISO, which operate the transmission system and dispatch generation to balance supply and demand regionwide, as well as engage in regionwide planning and cost allocation to facilitate needed transmission development. Accordingly, generating resources in one part of an RTO/ISO, such as through an NGCC plant, can serve loads in other parts of the RTO/ISO, as well as serving load areas outside of the RTO/ISO. As we consider each of these geographic areas in the memorandum, *Geographic Availability of CCS for New Base Load NGCC Units,* we make key points as to why this final rule does not negatively impact the ability of these regions to access new NGCC generation to the extent that NGCC generation is needed to supply demand and/or those regions

[797] In this discussion, the term RTO indicates both ISOs and RTOs.

[798] *https://prairiestateenergycampus.com/about/ownership/.*

[799] *https://www.ipautah.com/participants-services-area/.*

[800] Portland General Electric, ''Our Power Plants,'' *https://portlandgeneral.com/about/who-we-are/how-we-generate-energy/our-power-plants.*

[801] See George Plaven, ''PGE power plant rising in E. Oregon,'' The Columbian (October 10, 2015, 5:55 a.m.), *https://www.columbian.com/news/2015/oct/10/pge-power-plant-rising-in-e-oregon/.* See also Portland General Electric, ''PGE Service Area,'' *https://portlandgeneral.com/about/info/service-area.*

want to include new NGCC generation in their resource mixes.

(C) Costs

The EPA has evaluated the costs of CCS for new combined cycle units, including the cost of installing and operating CO_2 capture equipment as well as the costs of transport and storage. The EPA has also compared the costs of CCS for new combined cycle units to other control costs, in part derived from other rulemakings that the EPA has determined to be cost-reasonable, and the costs are comparable. Based on these analyses, the EPA considers the costs of CCS for new combined cycle units to be reasonable. Certain elements of the transport and storage costs are similar for new combustion turbines and existing steam generating units. In this section, the EPA outlines these costs and identifies the considerations specific to new combustion turbines. These costs are significantly reduced by the IRC section 45Q tax credit.

(1) Capture Costs

According to the NETL Fossil Energy Baseline Report (October 2022 revision), before accounting for the IRC section 45Q tax credit for sequestered CO_2, using a 90 percent capture amine-based post-combustion CO_2 capture system increases the capital costs of a new combined cycle EGU by 115 percent on a $/kW basis, increases the heat rate by 13 percent, increases incremental operating costs by 35 percent, and derates the unit (*i.e.,* decreases the capacity available to generate useful output) by 11 percent.[802] For a base load combustion turbine, carbon capture increases the LCOE by 62 percent (an increase of 27 $/MWh) and has an estimated cost of $81/ton ($89/metric ton) of onsite CO_2 reduction.[803] The NETL costs are based on the use of a second-generation amine-based capture system without exhaust gas recirculation (EGR) and, as discussed below, do not take into account further cost reductions that can be expected to occur from efficiency improvements as post-combustion capture systems are more widely deployed, as well as potential technological developments.[804]

The flue gas from natural gas-fired combined cycle turbine differs from that of coal-fired EGUs in several ways that impact the cost of CO_2 capture. These include that the CO_2 concentration in the flue gas is approximately one-third of that observed at coal-fired EGUs, the volumetric flow rate on a per MW basis is larger, and the oxygen concentration is approximately 3 times that of a coal-fired EGU. While the higher amount of excess oxygen has the potential to reduce the efficiency of amine-based solvents that are susceptible to oxidation, natural gas post-combustion flue gas does not have other impurities (SO_2, PM, trace metals) that are present and must be managed in coal flue gas. Other important factors include that the lower concentrations of CO_2 reduce the efficiency of the capture process and that the larger volumetric flow rates require a larger CO_2 absorber, which increases the capital cost of the capture process. Exhaust gas recirculation (EGR), also referred to as flue gas recirculation (FGR), is a process that addresses all these issues. EGR diverts some of the combustion turbine exhaust gas back into the inlet stream for the combustion turbine. Doing so increases the CO_2 concentration and decreases the O_2 concentration in the exhaust stream and decreases the flow rate, producing more favorable conditions for CCS. One study found that EGR can decrease the capital costs of a combined cycle EGU with CCS by 6.4 percent, decrease the heat rate by 2.5 percent, decrease the LCOE by 3.4 percent, and decrease the overall CO_2 capture costs by 11 percent relative to a combined cycle EGU without EGR.[805] The EPA notes that the NETL costs on which the EPA bases its cost calculations for combined cycle CCS do not assume the use of EGR, but as discussed below, EGR use is plausible and would reduce those costs.

While the costs considered in the preceding are based on the current costs of CCS, the EPA notes that the costs of capture systems can be expected to decrease over the rest of this decade and continue to decrease afterwards.[806] As part of the plan to reduce the costs of CO_2 capture, the DOE is funding multiple projects to further advance CCS technology from various point sources, including combined cycle turbines, cement manufacturing plants, and iron and steel plants.[807] It should be noted that some of these projects may be EPAct05-assisted. The general aim is to lower the costs of the technologies, and to increase investor confidence in the commercial scale applications, particularly for newer technologies or proven technologies applied under unique circumstances. In particular, OCED's Carbon Capture Demonstration Projects are targeted to accelerate continued power sector carbon capture commercialization through reducing costs and reducing uncertainties to project development. These cost and uncertainty reductions arise from reductions in cost of capital, increases in system scale, standardization and reduction in non-recurring engineering costs, maturation of supply chain ecosystem, and improvements in engineering design and materials over time.[808]

Although current post-combustion CO_2 capture projects have primarily been based on amine capture systems, there are multiple alternate capture technologies in development—many of which are funded through industry research programs—that could yield reductions in capital, operating, and auxiliary power requirements and could reduce the cost of capture significantly or improve performance. More specifically, post combustion carbon capture systems generally fall into one of several categories: solvents, sorbents, membranes, cryogenic, and molten carbonate fuel cells[809] systems. It is

[802] CCS reduced the net output of the NETL F class combined cycle EGU from 726 MW to 645 MW.

[803] Although not our primary approach to assessing costs in this final rule, for consistency with the proposal's assumption capacity factor, these calculations use a service life of 30 years, an interest rate of 7.0 percent, a natural gas price of $3.61/MMBtu, and a capacity factor of 65 percent. These costs do not include CO_2 transport, storage, or monitoring costs.

[804] Recent DOE analysis has compared the NETL costs with more recent FEED study costs and expert interviews and determined they are consistent after accounting for differences in inflation, economic assumptions, and other technology details. *Portfolio Insights: Carbon Capture in the Power Sector,* DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[805] Energy Procedia. (2014). *Impact of exhaust gas recirculation on combustion turbines. Energy and economic analysis of the CO_2 capture from flue gas of combined cycle power plants. https://www.sciencedirect.com/science/article/pii/S1876610214001234.*

[806] For example, see the article *CCUS Market Outlook 2023: Announced Capacity Soars by 50%,* which states, ''New gas power plants with carbon capture, for example, could be cheaper than unabated power in Germany as early as next year when coupled with the carbon price.'' *https://about.bnef.com/blog/ccus-market-outlook-2023-announced-capacity-soars-by-50/.*

[807] The DOE has also previously funded FEED studies for natural gas-fired combined cycle turbine facilities. These include FEED studies at existing combined cycle turbine facilities at Panda Energy Fund in Texas, Elk Hills Power Plant in Kern County, California, Deer Park Energy Center in Texas, Delta Energy Center in Pittsburg, California, and utilization of a Piperazine Advanced Stripper (PZAS) process for CO_2 capture conducted by The University of Texas at Austin.

[808] *Portfolio Insights: Carbon Capture in the Power Sector* report. DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[809] Molten carbonate fuel cells are configured for emissions capture through a process where the flue gas from an EGU is routed through the molten carbonate fuel cell that concentrates the CO_2 as a side reaction during the electric generation process

expected that as CCS infrastructure increases, technologies from each of these categories will become more economically competitive. For example, advancements in solvents that are potentially direct substitutes for current amine-solvents will reduce auxiliary energy requirements and reduce both operating and capital costs, and thereby, increase the economic competitiveness of CCS.[810] Planned large-scale projects, pilot plants, and research initiatives will also decrease the capital and operating costs of future CCS technologies.

In general, CCS costs have been declining as carbon capture technology advances.[811] While the cost of capture has been largely dependent on the concentration of CO_2 in the gas stream, advancements in varying individual CCS technologies tend to drive down the cost of capture for other CCS technologies. The increase in CCS investment is already driving down the costs of near-future CCS technologies. The Global CCS Institute has tracked publicly available information on previously studied, executed, and proposed CO_2 capture projects.[812] The cost of CO_2 capture from low-to-medium partial pressure sources such as coal-fired power generation has been trending downward over the past decade, and is projected to fall by 50 percent by 2025 compared to 2010. This is driven by the familiar learning-processes that accompany the deployment of any industrial technology. A review of learning rates (the reduction in cost for a doubling of production or capacity) for various energy related technologies similar to carbon capture (flue gas desulfurization, selective catalytic reduction, combined cycle turbines, pulverized coal boilers, LNG production, oxygen production, and hydrogen production via steam methane reforming) demonstrated learning rates of 5 percent to 27 percent for both capital expenditures and operations and maintenance costs.[813] [814] Studies of the cost of capture and compression of CO_2 from power stations completed 10 years ago averaged around $95/metric ton ($2020). Comparable studies completed in 2018/2019 estimated capture and compression costs could fall to approximately $50/metric ton CO_2 by 2025. Current target pricing for announced projects at coal-fired steam generating units is approximately $40/metric ton on average, compared to Boundary Dam whose actual costs were reported to be $105/metric ton, noting that these estimates do not include the impact of the 45Q tax credit as enhanced by the IRA. Additionally, IEA suggests this trend will continue in the future as technology advancements ''spill over'' into other projects to reduce costs.[815] Similarly, EIA incorporates a minimum 20 percent reduction in carbon capture and sequestration costs by 2035 in their Annual Energy Outlook 2023 modeling in part to account for the impact of spillover and international learning.[816] The Annual Technology Baseline published by NREL with input from NETL projects a 10 percent reduction in capital expenditures from 2021 through 2032 in the ''Conservative Technology Innovation Scenario'' for natural gas carbon capture retrofit projects, under the assumption that only learning processes lead to future cost reductions and that there are no additional improvements from investments in targeted technology research and development.[817] In a recent case study of the cost and performance of carbon capture retrofits on existing natural gas combined cycle units, based on discussions with external technology providers, engineering consultants, asset developers, and applicants for DOE awards, DOE used a 25 percent capital cost reduction estimate to illustrate the potential future capital costs of an Nth-of-a-Kind facility, as well as ''conservatively model[ing]'' operating expense reductions at 1 percent, for a combined overall decrease in the levelized cost of energy of about 10 percent for the Nth-of-a-Kind facility compared to a First-of-a-Kind facility.[818] DOE further found this illustrative cost reduction estimate from learning through doing to be consistent with other studies that use hybrid engineering-economic and experience-curve approaches to estimate potential decreases in the levelized cost of energy of 10–11 percent for Nth-of-a-Kind plants compared with First-of-a-Kind plants.[819] [820] Policies in the IIJA and IRA are further increasing investment in CCS technology that can accelerate the pace of innovation and deployment.

(2) CO_2 Transport and Sequestration Costs

NETL's ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Sequestration Costs in NETL Studies'' provides an estimation of transport costs based on the CO_2 Transport Cost Model.[821] The CO_2 Transport Cost Model estimates costs for a single point-to-point pipeline. Estimated costs reflect pipeline capital costs, related capital expenditures, and operations and maintenance costs.

NETL's Quality Guidelines also provide an estimate of sequestration costs. These costs reflect the cost of site screening and evaluation, permitting and construction costs, the cost of injection wells, the cost of injection equipment, operation and maintenance costs, pore volume acquisition expense, and long-term liability protection. Permitting and construction costs also reflect the regulatory requirements of the UIC Class VI program and GHGRP subpart RR for geologic sequestration of CO_2 in deep saline formations. NETL calculates these sequestration costs on the basis of generic plant locations in the Midwest, Texas, North Dakota, and Montana, as described in the NETL energy system studies.[822]

in the fuel cell. FuelCell Energy, Inc. (2018). *SureSource Capture. https://www.fuelcellenergy.com/recovery-2/suresource-capture/.*

[810] DOE. *Carbon Capture, Transport, & Storage. Supply Chain Deep Dive Assessment.* February 24, 2022. *https://www.energy.gov/sites/default/files/2022-02/Carbon%20Capture%20Supply%20Chain%20Report%20-%20Final.pdf.*

[811] International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions—A new era for CCUS. https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus.* The same is true for CCS on coal-fired EGUs.

[812] Technology Readiness and Costs of CCS (2021). Global CCS Institute. *https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf.*

[813] *https://www.sciencedirect.com/science/article/pii/S1750583607000163.*

[814] As an additional example for cost reductions from learning processes via deployment achieved in other complex power generation projects, the most recent sustained deployment of 19 nuclear reactors in South Korea from 1989 through 2008 resulted in a 13 percent reduction in capital costs. *https://www.sciencedirect.com/science/article/pii/S0301421516300106.*

[815] International Energy Agency (IEA) (2020). *CCUS in Clean Energy Transitions—CCUS technology innovation. https://www.iea.org/reports/ccus-in-clean-energy-transitions/a-new-era-for-ccus.*

[816] Energy Information Administration (EIA) (2023). *Assumptions to the Annual Energy Outlook 2023: Electricity Market Module. https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.*

[817] National Renewable Energy Laboratory (NREL) (2023). *Annual Technology Baseline 2023. https://atb.nrel.gov/electricity/2023/fossil_energy_technologies.*

[818] *Portfolio Insights: Carbon Capture in the Power Sector.* DOE. 2024. *https://www.energy.gov/oced/portfolio-strategy.*

[819] *https://www.frontiersin.org/articles/10.3389/fenrg.2022.987166/full.*

[820] *https://www.sciencedirect.com/science/article/pii/S1750583607000163.*

[821] Grant, T., *et al.* ''Quality Guidelines for Energy System Studies; Carbon Dioxide Transport and Storage Costs in NETL Studies.'' National Energy Technology Laboratory. 2019. *https://www.netl.doe.gov/energy-analysis/details?id=3743.*

[822] National Energy Technology Laboratory (NETL), ''FE/NETL CO2 Saline Storage Cost Model (2017),'' U.S. Department of Energy, DOE/NETL–2018–1871, 30 September 2017. *https://netl.doe.gov/energy-analysis/details?id=2403.*

There are two primary cost drivers for a CO_2 sequestration project: the rate of injection of the CO_2 into the reservoir and the areal extent of the CO_2 plume in the reservoir. The rate of injection depends, in part, on the thickness of the reservoir and its permeability. Thick, permeable reservoirs provide for better injection and fewer injection wells. The areal extent of the CO_2 plume depends on the sequestration capacity of the reservoir. Thick, porous reservoirs with a good sequestration coefficient will present a small areal extent for the CO_2 plume and have lower testing and monitoring costs. NETL's Quality Guidelines model costs for a given cumulative storage potential.[823]

In addition, provisions in the IIJA and IRA are expected to significantly increase the CO_2 pipeline infrastructure and development of sequestration sites, which, in turn, are expected to result in further cost reductions for the application of CCS at a new combined cycle EGUs. The IIJA establishes a new Carbon Dioxide Transportation Infrastructure Finance and Innovation program to provide direct loans, loan guarantees, and grants to CO_2 infrastructure projects, such as pipelines, rail transport, ships and barges.[824] The IIJA also establishes a new Regional Direct Air Capture Hubs program which includes funds to support four large-scale, regional direct air capture hubs and more broadly support projects that could be developed into a regional or inter-regional network to facilitate sequestration or utilization.[825] DOE is additionally implementing IIJA section 40305 (Carbon Storage Validation and Testing) through its CarbonSAFE initiative, which aims to further development of geographically widespread, commercial-scale, safe storage.[826] The IRA increases and extends the IRC section 45Q tax credit, discussed next.

(3) IRC Section 45Q Tax Credit

For the reasons explained in section VII.C.1.a.ii of this preamble, in determining the cost of CCS, the EPA is taking into account the tax credit provided under IRC section 45Q, as revised by the IRA. The tax credit is available at $85/metric ton ($77/ton) and offsets a significant portion of the capture, transport, and sequestration costs noted above.

(4) Total Costs of CCS

In a typical NSPS analysis, the EPA amortizes costs over the expected operating life of the affected facility and assumes constant revenue and expenses over that period of time. For a new combustion turbine, the expected operating life is 30 years. The EPA has adjusted that analysis in this rule to account for the fact that the IRC section 45Q tax credit is available for only the 12 years after operation is commenced. Since the duration of the tax credit is less than the expected life of a new base load combustion turbine, the EPA conducted the costing analysis by recognizing that the substantial revenue available for sequestering CO_2 during the first 12 years of operation is expected to result in higher capacity factors for that period, and the potential higher operating costs during the subsequent 18 years when the 45Q tax credit is not available is likely to result in lower capacity factors (see final TSD, *Greenhouse Gas Mitigation Measures, Carbon Capture and Storage for Combustion Turbines* for more discussion).[827] [828]

Specifically, the EPA's cost analysis assumes that the combined cycle turbine operates at a capacity of 80 percent over the initial 12-year period. This capacity level is generally consistent with the IPM model projections of 87 percent (and, in fact, somewhat more conservative). The 80 percent capacity factor assumption is also less than the 85 percent capacity factor assumption in the NETL analysis.[829] But notably, the higher capacity factors in the IPM analysis and in the NETL analysis suggest that higher capacity factors may be reasonable and as figure 8 in the final TSD, *Greenhouse Gas Mitigation Measures, Carbon Capture and Storage for Combustion Turbines* demonstrates, would result in even lower costs. The analysis further assumes that the turbine operates at a capacity of 31 percent during the remaining 18-year period. As explained in the final TSD, *Greenhouse Gas Mitigation Measures Carbon Capture and Storage for Combustion Turbines,* to avoid impacting the compliance costs due to changes in the overall capacity factors with the base case, the EPA kept the overall 30-year capacity factor at the historical average of 51 percent. The EPA evaluated several operational scenarios (as described in the TSD). The scenario with an initial 12-year capacity factor of 80 percent and a subsequent 18-year capacity factor of 31 percent (for a 30-year capacity factor of 51 percent) represents the primary policy case. It should be noted that at a 31 percent capacity factor, the combustion turbine would be subcategorized as an intermediate load combustion turbine, and therefore would be subject to a less stringent standard of performance that is based on efficient operation, not on the use of CCS.

This costing approach results in lower compliance costs than assuming a constant capacity factor for the 30-year useful life of the turbine because of increased revenue from generation during the initial 12-year period, increased revenue from the IRC section 45Q tax credits during that period, and lower costs during the last 18 years when the tax credit is not available. As noted, this is a reasonable approach because the economic incentive provided by the tax credit is so significant on a $/ton basis that the EPA expects sources to dispatch at higher levels while the tax credit is in effect.

The EPA calculated two sets of CCS costs: the first assumes that the turbine continues to operate the capture system during the last 18 years, and the second assumes that the turbine does not operate the capture system during the last 18 years.[830] Assuming continued operation of the capture equipment, the compliance costs are $15/MWh and $46/ton ($51/metric ton) for a 6,100 MMBtu/h H-Class turbine, which has a net output of approximately 990 MW; and $19/MWh and $57/ton ($63/metric ton) for a 4,600 MMBtu/h F-Class turbine, which has a net output of

[823] Department of Energy. Regional Direct Air Capture Hubs. (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[824] DOE. Carbon Dioxide Transportation Infrastructure. *https://www.energy.gov/lpo/carbon-dioxide-transportation-infrastructure.*

[825] Department of Energy. ''Regional Direct Air Capture Hubs.'' (2022). *https://www.energy.gov/oced/regional-direct-air-capture-hubs.*

[826] For more information, see the NETL announcement. *https://www.netl.doe.gov/node/12405.*

[827] In the proposal, the EPA used a constant 65 percent capacity factor, representative of the initial capacity factor of recently constructed combined cycle turbines, and effective 30-year 45Q tax credit of $41/ton. For this final rule, the EPA considers the approach of using a higher capacity factor for the first 12 years and a lower one for the last 18 years to reflect more accurately actual operating conditions, and therefore to be a more realistic basis for calculating CCS costs.

[828] The EPA's cost approach for CCS for existing coal-fired units also assumed that those units would increase their capacity during the 12-year period when the 45Q tax credit was available. See preamble section VII.C.1.a.ii, and *Greenhouse Gas Mitigation Measures for Steam Generating Units* TSD section 4.7.5. Because coal-fired power plants are existing plants, the EPA calculated CCS costs by assuming a 12-year amortization period for the CCS equipment, and the EPA did not need to make any assumptions about the operation of the coal-fired unit after the 12-year period.

[829] Compliance costs would be lower if higher capacity factors were used during the first 12 years of operation.

[830] The CCS and CO_2 TS&M costs are amortized over the period the equipment is operated—30 years or 12 years.

approximately 700 MW.[831] [832] If the capture system is not operated while the combustion turbine is subcategorized as an intermediate load combustion turbine, the compliance costs are reduced to $8/MWh and $43/ton ($47/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $12/MWh and $60/ton ($66/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. All of these costs are comparable to the cost metrics that, based on prior rules, the EPA finds to be reasonable in this rulemaking.[833] For a more detailed discussion of costs, see the TSD—*GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* section 2.3, Figure 12a.

The EPA considers these CCS cost estimates to be conservatively high because they do not take into account cost improvements from the potential use of exhaust gas recirculation, which, according to one study, could lower LCOE by 3.4 percent, as described in preamble section VIII.F.4.c.iv.(C)(1). Nor do they consider the potential for additional efficiency improvements for combined cycle units [834] or CCS technological advances, as discussed in preamble section VIII.F.4.c.iv.(B)(1)(b), VIII.F.4.c.iv.(C)(1), and RTC section 3.1. The EPA considers that at least some of these cost improvements are likely. Accordingly, the EPA also calculated the CCS costs based on an assumed 5 percent reduction in costs, in order to approximate these likely improvements, as follows: Assuming continued operation of the capture equipment, the compliance costs are $13/MWh and $40/ton ($44/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $18/MWh and $54/ton ($59/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. If the capture system is not operated while the combustion turbine is subcategorized as in intermediate load combustion turbine, the compliance costs are reduced to $8/MWh and $39/ton ($43/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $11/MWh and $56/ton ($61/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine.

In addition, the EPA considers all those costs to be conservative (in favor of higher costs) because they assume that the combustion turbine operator will not receive any revenues from captured CO_2 after the 12-year period for the tax credit. In fact, it is plausible that there will be sources of revenue, potentially including from the sale of the CO_2 for utilization and credits to meet state or corporate clean energy goals, as discussed in RTC section 2.2.4.3.

It should be noted that natural gas-fired combustion turbines with CCS may well generate at higher capacity factors after the expiration of the 45Q tax credit than the EPA's above-described BSER cost analysis assumes. In fact, the EPA's IPM model projects that the natural gas combined cycle generation that is projected to install CCS in the illustrative final rule scenario operates at an average 73 percent capacity factor, due to existing state regulatory requirements, during the 2045 model year, which is after the expiration of the 45Q tax credit. In addition, as discussed in RTC section 2.2.4.3, it is plausible that following the 12-year period of the tax credit, by the 2040s, cost improvements in CCS operations, more widespread adoption of CO_2 emission limitation requirements in the electricity sector, and greater demand for CO_2 for beneficial uses will support continued operation of fossil fuel-fired generation with CCS. Accordingly, the EPA also calculated CCS costs assuming that new F-Class and H-Class combustion turbines with CCS generate at a constant capacity factor of at least 60 percent, and up to 80 percent, during their 30-year useful life. In this calculation, the EPA amortized the costs of CCS over the 30-year useful life of the turbine. The EPA includes these costs in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* section 2.3, Figure 8.[835] At the lower levels of capacity, costs are higher than described above (which assumed 80 percent capacity during the first 12 years), but even at those lower levels, the costs are broadly consistent with the cost-reasonable metrics based on prior rules, particularly when those costs are reduced by an additional 5 percent to account for improved efficiency and other factors, as noted above. Nonetheless, consistent with the EPA's commitment to review, and if appropriate, revise the emission guidelines for coal-fired steam generating units as discussed in section VII.F, the EPA also intends to evaluate, by 2041, the continued cost-reasonableness of CCS for natural gas-fired combustion turbines in light of these potential significant developments, and will consider at that time whether a future regulatory action may be appropriate.

(5) Comparison to Other Costs of Controls

The costs for CCS applied to a representative new base load stationary combustion turbine EGU are generally lower than the costs of other controls in EPA rules for fossil fuel-fired electric generating units, as well as the costs of other controls for greenhouse gases, as described in section VII.C.1.a.ii(D), which supports the EPA's view that the CCS costs are reasonable.

(D) Non-Air Quality Health and Environmental Impact and Energy Requirements

In this section of the preamble, the EPA considers the non-air quality health and environmental impacts of CCS for new combined cycle turbines and concludes there are limited consequences related to non-air quality health and environmental impact and energy requirements. The EPA first discusses energy requirements, and then considers non-GHG emissions impacts and water use impacts, resulting from the capture, transport, and sequestration of CO_2.

With respect to energy requirements, including a 90 percent or greater carbon capture system in the design of a new combined cycle turbine will increase the unit's parasitic/auxiliary energy demand and reduce its net power output. A utility that wants to construct a combined cycle turbine to provide 500 MWe-net of power could build a

[831] The output of the H-Class model combined cycle EGU without CCS is 992 MW. The auxiliary load of CCS reduces the net out to 883 MW. The output of the F-Class model combined cycle EGU without CCS is 726 MW. The auxiliary load of CCS reduces the net out to 645 MW.

[832] As we explain in the final TSD, *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines,* sections 2.3–2.5, the 6,100 MMBtu/h H-Class combustion turbine is the median size of recently constructed combined cycle facilities and the 4,600 MMBtu/h F-Class combustion turbine approximates the size of a number of recently constructed combined cycle facilities as well. CCS costs for smaller sources are higher but are not prohibitive. *GHG Mitigation Measures—Carbon Capture and Storage for Combustion Turbines* TSD, section 2.3, Figures 12a and 13. As noted in RTC section 3.1, we expect costs to decrease due to learning by doing and technological development. In addition, since the incremental generating costs of larger more efficient combined cycle turbines are lower relative to smaller combined cycle turbines, it is more likely that larger more efficient combined cycle turbine will operate as base load combustion turbines.

[833] A DOE analysis of a representative NGCC plant using CCS in the ERCOT market indicates that operating at high operating capacity could be profitable today with the IRC 45Q tax credits. *Portfolio Insights: Carbon Capture in the Power Sector.* DOE. *https://www.energy.gov/oced/portfolio-strategy.*

[834] These additional efficiency improvements are noted in the final TSD, *Efficient Generation: Combustion Turbine Electric Generating Units.*

[835] The compliance costs assume the same capacity factors in the base and policy case, that is, without CCS and with CCS. If combined cycle turbine with CCS were to operate at higher capacity factors in the policy case, compliance costs would be reduced.

500 MWe-net plant knowing that it will be de-rated by 11 percent (to a 444 MWe-net plant) with the installation and operation of CCS. In the alternative, the project developer could build a larger 563 MWe-net combined cycle turbine knowing that, with the installation of the carbon capture system, the unit will still be able to provide 500 MWe-net of power to the grid. Although the use of CCS imposes additional energy demands on the affected units, those units are able to accommodate those demands by scaling larger, as needed.

Regardless of whether a unit is scaled larger, the installation and operation of CCS itself does not impact the unit's potential-to-emit any criteria air pollutants. In other words, a new base load stationary combustion turbine EGU constructed using highly efficient generation (the first component of the BSER) would not see an increase in emissions of criteria air pollutants as a direct result of installing and using 90 percent or greater CO_2 capture CCS to meet the second phase standard of performance.[836]

Scaling a unit larger to provide heat and power to the CO_2 capture equipment would have the potential to increase non-GHG air emissions. However, most pollutants would be mitigated or controlled by equipment needed to meet other CAA requirements. In general, the emission rates and flue gas concentrations of most non-GHG pollutants from the combustion of natural gas in stationary combustion turbines are relatively low compared to the combustion of oil or coal in boilers. As such, it is not necessary to use an FGD to pretreat the flue gas prior to CO_2 removal in the CO_2 scrubber column. The sulfur content of natural gas is low relative to oil or coal and resulting SO_2 emissions are therefore also relatively low. Similarly, PM emissions from combustion of natural gas in a combustion turbine are relatively low. Furthermore, the high combustion efficiency of combustion turbines results in relatively low HAP emissions. Additionally, combustion turbines at major sources of HAP are subject to the stationary combustion turbine NESHAP, which includes limits for formaldehyde emissions for new sources that may require installation of an oxidation catalyst (87 FR 13183; March 9, 2022). Regarding NO_X emissions, in most cases, the combustion turbines in new combined cycle units will be equipped with low-NO_X burners to control flame temperature and reduce NO_X formation. Additionally, new combined cycle units are typically subject to major NSR requirements for NO_X emissions, which may require the installation of SCR to comply with a control technology determination by the permitting authority. See section XI.A of this preamble for additional details regarding the NSR program. Although NO_X concentrations may be controlled by SCR, for some amine solvents NO_X in the post-combustion flue gas can react in the CO_2 absorber to form nitrosamines. A conventional multistage water wash or acid wash and a mist eliminator at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.,* nitrosamine) emissions.[837] [838] Acetaldehyde and formaldehyde can form through oxidation of the solvent, however, this can be mitigated by selecting compatible materials to limit catalytic oxidation and interstage cooling in the absorber to limit thermal oxidation.

The use of water for cooling presents an additional issue. Due to their relatively high efficiency, combined cycle EGUs have relatively small cooling requirements compared to other base load EGUs. According to NETL, a combined cycle EGU without CCS requires 190 gallons of cooling water per MWh of electricity. CCS increases the cooling water requirements due both to the decreased efficiency and the cooling requirements for the CCS process to 290 gallons per MWh, an increase of about 50 percent. However, because combined cycle turbines require limited amounts of cooling water, the absolute amount of increase in cooling water required due to use of CCS is relatively small compared to the amount of water used by a coal-fired EGU. A coal-fired EGU without CCS requires 450 gallons or more per MWh and the industry has demonstrated an ability to secure these quantities of water and the EPA has determined that the increased water requirements for CCS can be addressed. In addition, many combined cycle EGUs currently use dry cooling technologies and the use of dry or hybrid cooling technologies for the CO_2 capture process would reduce the need for additional cooling water. Therefore, the EPA is finalizing a determination that the challenges of additional cooling requirements from CCS are limited and do not disqualify CCS from being the BSER.

Stakeholders have shared with the EPA concerns about the safety of CCS projects and that historically disadvantaged and overburdened communities may bear a disproportionate environmental burden associated with CCS projects.[839] The EPA takes these concerns seriously, agrees that any impacts to historically disadvantaged and overburdened communities are important to consider, and has done so as part of its analysis discussed at section XII.E. For the reasons noted above, the EPA does not expect CCS projects to result in uncontrolled or substantial increases in emissions of non-GHG air pollutants from new combustion turbines. Additionally, a robust regulatory framework exists to reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. These projects will likely be subject to major NSR requirements for their emissions of criteria pollutants, and therefore the sources would be required to (1) control their emissions of attainment pollutants by applying BACT and demonstrate the emissions will not cause or contribute to a NAAQS violation, and (2) control their emissions of nonattainment pollutants by applying LAER and fully offset the emissions by securing emission reductions from other sources in the area. Also, as mentioned in section VII.C.1, carbon capture systems that are themselves a major source of HAP should evaluate the applicability of CAA section 112(g) and conduct a case-by-case MACT analysis if required, to establish MACT for any listed HAP, including listed nitrosamines, formaldehyde, and acetaldehyde. But, as also discussed in section VII.C.1, a conventional multistage water or acid wash and mist eliminator (demister) at the exit of the CO_2 scrubber is effective at removal of gaseous amine and amine degradation products (*e.g.,* nitrosamine) emissions. Additionally, as noted in

[836] While the absolute onsite mass emissions would not increase from the second component of the BSER, the emissions rate on a lb/MWh-net basis would increase by 13 percent.

[837] Sharma, S., Azzi, M., ''A critical review of existing strategies for emission control in the monoethanolamine-based carbon capture process and some recommendations for improved strategies,'' *Fuel,* 121, 178 (2014).

[838] Mertens, J., *et al.,* ''Understanding ethanolamine (MEA) and ammonia emissions from amine-based post combustion carbon capture: Lessons learned from field tests,'' *Int'l J. of GHG Control,* 13, 72 (2013).

[839] In outreach with potentially vulnerable communities, residents have voiced two primary concerns. First, there is the concern that their communities have experienced historically disproportionate burdens from the environmental impacts of energy production, and second, that as the sector evolves to use new technologies such as CCS, they may continue to face disproportionate burden. This is discussed further in section XII.E of this preamble.

section VII.C.1.a.i.(C) of this preamble, PHMSA oversight of supercritical CO_2 pipeline safety protects against environmental release during transport and UIC Class VI regulations under the SDWA, in tandem with GHGRP requirements, ensure the protection of USDWs and the security of geologic sequestration.

The EPA is committed to working with its fellow agencies to foster meaningful engagement with communities and protect communities from pollution. This can be facilitated through the existing detailed regulatory framework for CCS projects and further supported through robust and meaningful public engagement early in the technological deployment process.

The EPA also expects that the meaningful engagement requirements discussed in section X.E.1.b.i of this preamble will ensure that all interested stakeholders, including community members who might be adversely impacted by non-GHG pollutants, will have an opportunity to raise this concern with states and permitting authorities. Additionally, state permitting authorities, and project developers are, in general, required to provide public notice and comment on permits for such projects. This provides additional opportunities for affected stakeholders to engage in that process, and it is the EPA's expectation that the responsible entities consider these concerns and take full advantage of existing protections. Moreover, the EPA through its regional offices is committed to thoroughly review permits associated with CO_2 capture.

(E) Impacts on the Energy Sector

The EPA does not believe that determining CCS to be BSER for base load combustion turbines will cause reliability concerns, for several independent reasons. First, the EPA is finalizing a determination that the costs of CCS are reasonable and comparable to other control requirements the EPA has required the electric power industry to adopt without significant effects on reliability. Second, base load combined cycle turbines are only one of many options that companies have to build new generation. The EPA expects there to be considerable interest in building intermediate load and low load combustion turbines to meet demand for dispatchable generation. Indeed, the portion of the combustion turbine fleet that is operating at base load is declining as shown in the EPA's reference case modeling (Power Sector Platform 2023 using IPM reference case, see section IV.F of the preamble). In 2023, combined cycle turbines are only expected to represent 14 percent of all new generating capacity built in the U.S. and only a portion of that is natural gas combined cycle capacity.[840] Several companies have recently announced plans to move away from new combined cycle turbine projects in favor of more non-base load combustion turbines, renewables, and battery storage. For example, Xcel recently announced plans to build new renewable power generation instead of the combined cycle turbine it had initially proposed to replace the retiring Sherco coal-fired plant.[841] Finally, while CCS is adequately demonstrated and cost-reasonable, this final rulemaking allows companies that want to build a base load combined cycle turbine another compliance option to meet its requirements: building a unit that co-fires low-GHG hydrogen in the appropriate amount to meet the standard of performance. In fact, companies are currently pursuing both of these options—units with CCS as well as units that will co-fire low-GHG hydrogen are both in various stages of development. For these reasons, determining CCS to be the BSER for base load units will not cause reliability concerns.

(F) Extent of Reductions in CO_2 Emissions

Designating CCS as a component of the BSER for certain base load combustion turbine EGUs prevents large amounts of CO_2 emissions. For example, a new base load combined cycle EGU without CCS could be expected to emit 45 million tons of CO_2 over its 30-year operating life, or 1.5 million tons of CO_2 per year. Use of CCS would avoid the release of nearly 41 million tons of CO_2 over the operating life of the combined cycle EGU, or 1.37 million tons per year. However, due to the auxiliary/parasitic energy requirements of the carbon capture system, capturing 90 percent of the CO_2 does not result in a corresponding 90 percent reduction in CO_2 emissions. According to the NETL baseline report, adding a 90 percent CO_2 capture system increases the EGU's gross heat rate by 7 percent and the unit's net heat rate by 13 percent. Since more fuel would be consumed in the CCS case, the gross and net emissions rates are reduced by 89.3 percent and 88.7 percent respectively. These amounts of CO_2 emissions and reductions are larger than for any other industrial source, except for coal-fired steam generating units.

(G) Promotion of the Development and Implementation of Technology

The EPA also considered whether determining CCS to be a component of the BSER for new base load combustion turbines will advance the technological development of CCS and concluded that this factor further corroborates our BSER determination. A standard of performance based on highly efficient generation in combination with the use of CCS—combined with the availability of IRC section 45Q tax credits and investments in supporting CCS infrastructure from the IIJA—should result in more widespread adoption of CCS. In addition, while solvent-based CO_2 capture has been adequately demonstrated at the commercial scale, a CCS-based standard of performance may incentivize the development and use of better-performing solvents or other components of the capture equipment.

Furthermore, the experience gained by utilizing CCS with stationary combustion turbine EGUs, with their lower CO_2 flue gas concentration relative to other industrial sources such as coal-fired EGUs, will advance capture technology with other lower CO_2 concentration sources. The EIA 2023 Annual Energy Outlook projects that almost 862 billion kWh of electricity will be generated from natural gas-fired sources in 2040.[842] Much of that generation is projected to come from existing combined cycle EGUs and further development of carbon capture technologies could facilitate increased retrofitting of those EGUs.

(H) Summary of BSER Determination

As discussed, the EPA is finalizing a determination that the second component of the BSER for base load stationary combustion turbines is the utilization of CCS at 90 percent capture. The EPA has determined that 90 percent CCS meets the criteria for BSER for new base load combustion turbines. It is an adequately demonstrated technology that can be implemented a reasonable cost. Importantly, use of CCS at 90 percent capture results in significant reductions of CO_2 as compared to a base load combustion turbine without CCS. In addition, the EPA has considered non-air quality and energy impacts. Considering all these factors together, with particular emphasis on the importance of significantly reducing carbon pollution from these heavily utilized sources, the EPA concludes that

[840] *https://www.eia.gov/todayinenergy/detail.php?id=55419.*

[841] *https://cubminnesota.org/xcel-is-no-longer-pursuing-gas-power-plant-proposes-more-renewable-power/.*

[842] Does not include 114 billion kilowatt hours from natural gas-fired CHP projected in AEO 2023.

CCS at 90 percent capture is BSER for new base load combustion turbines. In addition, selecting CCS at 90 percent capture further promotes the development and implementation of this critical carbon pollution reduction technology, which confirms the appropriateness of determining it to be the BSER.

The BSER for base load combustion turbines contains two components and the EPA is promulgating standards of performance to be implemented in two phases with each phase reflecting the degree of emission reduction achievable through the application of each component of the BSER. The first component of the BSER is most efficient generation—an affected new base load combustion turbine must be constructed (or reconstructed) to meet a phase 1 emission standard that reflects the emission rate of the best performing combustion turbine systems. The phase 1 standard of performance for base load combustion turbines is in effect immediately once the source begins operation. The second component of the BSER, as just discussed, is use of CCS at a 90 percent capture rate. The phase 2 standard of performance for base load combustion turbines reflects the implementation of 90 capture CCS on a highly efficient combined cycle combustion turbine system. The compliance date begins January 1, 2032.

(I) January 2032 Compliance Date

The EPA proposed a compliance date beginning January 1, 2035, for new and reconstructed base load stationary combustion turbines subject to the phase 2 standard of performance based on CCS as the BSER. Some commenters were supportive of the proposed compliance date and some urged the EPA to set an earlier compliance date; the EPA also received comments on the proposed rule that stated that the proposed compliance date was not achievable and referenced longer project timelines for CO_2 capture. The EPA has considered the comments and information available and is finalizing a compliance date of January 1, 2032, for the phase 2 standard of performance for base-load stationary combustion turbines. The EPA is also finalizing a mechanism for a compliance date extension of up to 1 year in cases where a source faces a delay in the installation and startup of controls that are beyond the control of the EGU owner or operator, as detailed in section VIII.N of this preamble.

In total, the January 1, 2032, compliance date allows for more than 7 years for installation of CCS after issuance of this rule for sources that have recently commenced construction. This is consistent with the extended project schedule in the Sargent & Lundy report. This is also greater than the approximately 6 years from start to finish for Boundary Dam Unit 3 and Petra Nova.

As discussed in section VII.C.1.a.i(E), the timing for installation of CCS on existing coal-fired steam generating units is based on the baseline project schedule for the capture plant developed by Sargent and Lundy (S&L) [843] and a review of the available information for installation of CO_2 pipelines and sequestration sites.[844] The representative timeline for CCS for coal-fired steam generating units is detailed in the final TSD, *GHG Mitigation Measures for Steam Generating Units,* available in the docket, and the anticipated timeline for development of a CCS project for application at a new or reconstructed base load stationary combustion turbine would be similar. The explanations the EPA provided in section VII.C.1.a.i(E) regarding the timeline for long-term coal-fired steam generating units generally apply to new combustion turbines as well. The EPA expects that the owners or operators of affected combustion turbines will be able to complete the design, planning, permitting, engineering, and construction steps for the carbon capture and transport and storage systems in a similar amount of time as projects for coal-fired EGUs.

While those considerations apply in general, the EPA notes that the timeline for the installation of CCS on coal-fired steam generating units accounted for the state plan development process. Because there are not state plans required for new combustion turbines, new sources can commit to beginning substantial work earlier (*e.g.,* FEED studies, right-of-way acquisition), immediately after the completion of feasibility work. However, the EPA also recognizes that other elements of a state plan (*e.g.,* RULOF), by which a source under specific circumstances could have a later compliance date, are not available to new sources. Therefore, while the timeline for CCS on coal-fired steam generating units is based on the baseline S&L capture plant schedule (about 6.25 years), the EPA bases the timeline for CCS on new combustion turbines on the extended S&L capture plant schedule (7 years).

As discussed, base load stationary combustion turbines that commence construction or reconstruction on or after May 23, 2023, are subject to standards of performance that are implemented initially in two phases. New stationary combustion turbines that are designed and constructed for the purpose of operating in the base load subcategory (*i.e.,* at a 12-operating month capacity factor of greater than 40 percent) that hypothetically commenced construction on May 23, 2023, could, according to the schedule allowing, conservatively, up to 7 years to develop a CCS project, have a system constructed and on-line by May 23, 2030. However, the EPA is finalizing a compliance date of January 1, 2032, because some base load combined cycle stationary combustion projects that commenced construction between May 23, 2023, and the date of this final rule, may not have included CCS in the original design and planning for the new EGU and, therefore, would be unlikely to be able to have an operational CCS system available by May 23, 2030.

Further, the EPA notes that a delayed compliance date (of January 1, 2035) was proposed for the phase 2 standards of performance due to overlapping demands on the capacity to design, construct, and operate carbon capture systems as well as pipeline systems that would potentially be needed to support CCS projects for existing steam generating units and other industrial sources. As discussed in section VII.C.1.a.i(E), in this action the EPA is finalizing a compliance date of January 1, 2032 for long term coal-fired steam generating EGUs to meet a standard of performance based on 90 percent capture CCS. This compliance date for long-term coal-fired steam generating EGUs places fewer demands on the capacity to design, construct, and operate carbon capture systems and the associated infrastructure for those sources. Therefore, the EPA does not believe that there is a need to extend the compliance date for phase 2 standards for base load combustion turbine EGUs by 5 years beyond that for existing coal-fired steam generating EGUs, as proposed.

Considering these factors, the EPA is therefore finalizing the compliance date of January 1, 2032 for base load combustion turbine EGUs to meet the phase 2 standard of performance. This is the same compliance date applicable to existing long term coal-fired steam generating EGUs that are subject to a standard of performance based on 90 percent capture CCS. The EPA assumes the timelines for development of the various components of CCS for an existing coal-fired steam generating

[843] CO_2 Capture Project Schedule and Operations Memo, Sargent & Lundy (2024).

[844] Transport and Storage Timeline Summary, ICF (2024).

EGU, as discussed in section VII.C.1.a.i(E), are very similar for those components for a CCS system serving a new or reconstructed base load combustion turbine EGU.

Some commenters argued that because the power sector will require some amount of time before CCS and associated infrastructure may be installed on a widespread basis, CCS cannot be considered adequately demonstrated. This argument is similar to the argument, discussed in section V.C.2.b, that in order to be adequately demonstrated, a technology must be in widespread commercial use. Both arguments are incorrect. Under CAA section 111, for a control technology to qualify as the BSER, the EPA must demonstrate that it is adequately demonstrated for affected sources. The EPA must also show that the industry can deploy the technology at scale in the compliance timeframe. That the EPA has provided lead time in order to ensure adequate time for industry to deploy the technology at scale shows that the EPA is meeting its statutory obligation, not the inverse. Indeed, it is not at all unusual for the EPA to provide lead time for industry to deploy new technology. The EPA's approach is in line with the statutory text and caselaw encouraging technology-forcing standard-setting cabined by the EPA's obligation to ensure that its standards are reasonable and achievable.

CCS is clearly adequately demonstrated, and ripe for wider implementation. Nevertheless, the EPA acknowledged in the proposed rule, and reaffirms now, that the power sector will require some amount of lead time before individual plants can install CCS as necessary. Deploying CCS requires the building of capture facilities, pipelines to transport captured CO_2 to sequestration sites, and the development of sequestration sites. This is true for both existing coal-fired steam generating EGUs, some of which would be required to retrofit with CCS under the emission guidelines included in this final rulemaking, and new gas-fired combustion turbine EGUs, which must incorporate CCS into their construction planning.

In this final rulemaking, the EPA is setting a compliance deadline of January 1, 2032 for the CCS-based standard for new base load combustion turbines. The EPA determined, examining the evidence and exercising its appropriate discretion to do so, that this is a reasonable amount of time to allow for CCS buildout at the plant level. As the EPA explained at proposal, D.C. Circuit caselaw supports this approach. There, the EPA cited *Portland Cement* v. *Ruckelshaus,* for the proposition that ''D.C. Circuit caselaw supports the proposition that CAA section 111 authorizes the EPA to determine that controls qualify as the BSER—including meeting the 'adequately demonstrated' criterion—even if the controls require some amount of 'lead time,' which the court has defined as 'the time in which the technology will have to be available.' '' (footnote omitted). Nothing in the comments alters the EPA's view of the relevant legal requirements related to adequate demonstration or lead time.

d. BSER for Base Load Subcategory—Third Component

The EPA proposed a third component of the BSER of 96 percent (by volume) hydrogen co-firing in 2038 for owners/operators of base load combustion turbines that elected to comply with the low-GHG hydrogen co-firing pathway. As discussed in the next section, the EPA is not finalizing the proposed BSER pathway of low-GHG hydrogen co-firing at this time. Therefore, the Agency is not finalizing a third component of the BSER for base load combustion turbines.

5. Technologies Proposed by the EPA But Ultimately Not Determined To Be the BSER

The EPA is not finalizing its proposed BSER pathway of low-GHG hydrogen co-firing for new and reconstructed base load and intermediate load combustion turbines as part of this action. In light of public comments and additional analysis, uncertainties regarding projected costs prevent the EPA from determining that low-GHG hydrogen is a component of the BSER at this time.

The next section provides a summary of the proposed requirements for low-GHG hydrogen followed by, in section VIII.F.5.b, an explanation for why the Agency is not finalizing its proposed determination that low-GHG hydrogen co-firing is BSER. In section VIII.F.6, the EPA discusses considerations for the potential use of hydrogen. In section VIII.F.6.a, the Agency explains why it is not limiting the hydrogen that may be co-fired in a new or reconstructed combustion turbine to only low-GHG hydrogen. In section VIII.F.6.b, the Agency discusses its decision to not include a definition of low-GHG hydrogen.

a. Proposed Low-GHG Hydrogen Co-Firing BSER

The EPA proposed that new and reconstructed intermediate load combustion turbines were subject to a second component of the BSER that consisted of co-firing 30 percent (by volume) low-GHG hydrogen by 2032. The EPA also proposed that new and reconstructed base load combustion turbines could elect either (i) a second component of BSER that consisted of installing CCS by 2035, or (ii) a second and third component of BSER that consisted of co-firing 30 percent (by volume) low-GHG hydrogen by 2032 and co-firing 96 percent (by volume) low-GHG hydrogen by 2038.

The EPA solicited comment on whether the Agency should finalize both the CCS and low-GHG hydrogen co-firing pathways as separate subcategories with separate standards of performance and on whether the EPA should finalize one pathway with the option of meeting the standard of performance using either system of emission reduction (88 FR 33277, May 23, 2023). The EPA also solicited comment on the option of finalizing a single standard of performance based on the application of CCS for the base load subcategory (88 FR 33283, May 23, 2023).

b. Explanation for Not Finalizing Low-GHG Hydrogen Co-Firing as a BSER

The EPA is not finalizing a low-GHG hydrogen co-firing component of the BSER at this time. The EPA proposed that co-firing low-GHG hydrogen qualified as a BSER pathway because the components of the system met specific criteria, namely that the capability of combustion turbines to co-fire hydrogen was adequately demonstrated and there was a reasonable expectation that the necessary quantities of low-GHG hydrogen would be nationally available by 2032 and 2038 at reasonable cost. Due to concerns raised by commenters, the EPA conducted additional analysis of key components of the low-GHG hydrogen best system and the Agency's proposed determination that low-GHG hydrogen co-firing qualified as the BSER. This additional analysis, discussed further below, indicated that the currently estimated cost of low-GHG hydrogen in 2030 is higher than anticipated at proposal. These higher cost estimates were key factors in the EPA's decision to revise its 2030 cost estimate for delivered low-GHG hydrogen.

While the EPA is not finalizing a BSER determination with regard to co-firing with low-GHG hydrogen as part of this rulemaking and is therefore not making any determination about whether such a practice is adequately demonstrated, the Agency notes that there are multiple models of combustion turbines available from major manufacturers that have successfully

demonstrated the ability to combust hydrogen. Manufacturers have stated that they expect to have additional models of combustion turbines available that will be capable of firing 100 percent hydrogen while limiting emissions of other pollutants (*e.g.,* NO_X). The EPA further discusses considerations around the technical feasibility of hydrogen co-firing in new and reconstructed combustion turbines, and what they mean for the potential use of hydrogen co-firing as a compliance strategy, in section VIII.F.6 of this preamble.

While the EPA believes that hydrogen co-firing is technically feasible based on combustion turbine technology, information about how the low-GHG hydrogen production industry will develop in the future is not sufficiently certain for the EPA to be able to determine that adequate quantities will be available. That is, there remain, at the time of this final rulemaking, uncertainties pertaining to how the future nationwide availability of low-GHG hydrogen will develop. Relatedly, estimates of its future costs are more uncertain than anticipated at proposal. For low-GHG hydrogen to meet the BSER criteria as proposed, the EPA would have to be able to determine that significant quantities of low-GHG hydrogen will be available at reasonable costs such that affected sources in the power sector nationwide could rely on it for use by 2032 and 2038. While some analyses [845] show that this will likely be the case, the full set of information necessary to support such a determination is not available at this time. However, the EPA believes this may change as the low-GHG hydrogen industry continues to develop. The Agency plans to monitor the development of the industry; if appropriate, the EPA will reevaluate its findings and establish standards of performance that achieve additional emission reductions. Furthermore, as noted above, the EPA considers the co-firing of hydrogen to be technically feasible in multiple models of available combustion turbines.

As noted above, the EPA has revised its cost analysis of low-GHG hydrogen and determined that, due to the present uncertainty, estimated future hydrogen costs are higher than at proposal. The higher estimated cost of low-GHG hydrogen relative to proposal is the key factor in the EPA's decision to not finalize low-GHG hydrogen co-firing as a BSER pathway for new and reconstructed base load and intermediate load combustion turbines at this time.

In the proposal, the EPA modeled low-GHG hydrogen as a fuel available at a fixed delivered [846] price of $1/kg (or $7.40/MMBtu) in the baseline. This cost decreased to $0.50/kg (or $3.70/MMBtu) in the Integrated Proposal case when the second phase of the new combustion turbine standard began in 2032. This fuel was assumed to be ''clean'' and eligible for the highest subsidy under the IRC section 45V hydrogen production tax credit and would comply with the proposed requirement to use low-GHG hydrogen (88 FR 33314, May 23, 2023). The EPA's revised modeling of the power sector for the final rule used a price of $1.15/kg for delivered low-GHG hydrogen in both the final baseline and policy cases. For additional discussion of the EPA's revised modeling of the power sector and increased cost estimate for low-GHG hydrogen, see the final RIA included in the docket for this rulemaking.

The U.S. Department of Energy's 2022 report, *Pathways to Commercial Liftoff: Clean Hydrogen,* informed the EPA's revised low-GHG hydrogen cost analysis. According to the DOE report, the cost to produce, transport, store, and deliver low-GHG or ''clean'' hydrogen is expected to be between $0.70/kg and $1.15/kg by 2030 with the IRA's $3/kg maximum IRC section 45V production tax credit included.[847] The report also points out that the power sector is competing with other industrial sectors—such as transportation, ammonia and chemical production, oil refining, and steel manufacturing—in terms of potential downstream applications of clean hydrogen for the purpose of reducing GHG emissions. The DOE report also estimates that $0.40/kg to $0.50/kg is the price the power sector would be willing to pay for clean hydrogen.

Some analyses of future hydrogen costs provide estimates that are higher than those of the DOE. For example, public commenters estimated the cost of delivered ''clean'' hydrogen to be less than $3/kg by 2030 before declining to $2/kg by 2035. These estimates of delivered hydrogen costs include the IRC section 45V hydrogen production tax credits contained in the IRA, but they do not reflect regulations proposed by the U.S. Department of the Treasury pertaining to clean hydrogen production tax and energy credits, which proposed certain eligibility parameters (88 FR 89220, December 26, 2023). Until Treasury's regulations on the IRC section 45V hydrogen production tax credit are final, some analysts only estimate future production costs of hydrogen, not delivered costs, and do not include any projected potential impacts of the IRA incentives. For example, both McKinsey and BloombergNEF project the unsubsidized production cost of clean hydrogen to be approximately $2/kg by 2030, which could lead to negative to zero prices for some subsidized hydrogen after considering transportation and storage.[848] [849] One of the highest estimates for the unsubsidized production cost of clean hydrogen is from the Rhodium Group, which estimates the price to be from $3.39/kg to $4.92/kg in 2030.[850] Again, it should be noted these estimates do not include additional costs for transportation and storage. The increased cost projections for low-GHG hydrogen production are partly due to higher costs for capital equipment, such as electrolyzers. The DOE published a Program Record [851] detailing higher costs than previously estimated by levering data from the regional clean hydrogen hubs and other literature. Costs increases are predominantly driven by inflation, supply chain cost increases, and higher estimated installation costs. However, there is a significant range in electrolyzer costs; some companies cite costs that are significantly lower ($750-$900/kW installed cost) [852] than that published in the Program Record.

[845] Electric Power Research Institute (EPRI). (November 3, 2023). Impact of IRA's 45V Clean Hydrogen Production Tax Credit. White paper. *https://www.epri.com/research/products/000000003002028407.*

[846] The delivered price includes the cost to produce, transport, and store hydrogen.

[847] U.S. Department of Energy (DOE) (March 2023). *Pathways to Commercial Liftoff: Clean Hydrogen. https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf.*

[848] Heid, B.; Sator, A.; Waardenburg, M.; and Wilthaner, M. (25 Oct 2022). Five charts on hydrogen's role in a net-zero future. McKinsey & Company. *https://www.mckinsey.com/capabilities/sustainability/our-insights/five-charts-on-hydrogens-role-in-a-net-zero-future.*

[849] Schelling, K. (9 Aug 2023). Green Hydrogen to Undercut Gray Sibling by End of Decade. BloombergNEF. *https://about.bnef.com/blog/green-hydrogen-to-undercut-gray-sibling-by-end-of-decade/.*

[850] Larsen, J.; King, B.; Kolus, H.; Dasari, N.; Bower, G.; and Jones, W. (12 Aug 2022). A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act. Rhodium Group. *https://rhg.com/research/climate-clean-energy-inflation-reduction-act/.*

[851] U.S. Department of Energy (DOE). (February 22, 2024). *Summary of Electrolyzer Cost Data Synthesized from Applications to the DOE Clean Hydrogen Hubs Program.* DOE Hydrogen Program, Office of Clean Energy Demonstrations Program Record. *https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/24002-summary-electrolyzer-cost-data.pdf.*

[852] Martin, P. (December 18, 2023). What gives Bill Gates-backed start-up Electric Hydrogen the edge over other electrolyzer makers? Hydrogen

6. Considerations for the Potential Use of Hydrogen

The ability of combustion turbines to co-fire hydrogen can effectively reduce stack GHG emissions. Hydrogen also offers unique solutions for decarbonization because of its potential to provide dispatchable, clean energy with long-term storage and seasonal capabilities. For example, hydrogen is an energy carrier that can provide long-term storage of low-GHG energy that can be co-fired in combustion turbines and used to balance load with the increasing volumes of variable generation. These services support the reliability of the power system while facilitating the integration of variable zero-emitting energy resources and supporting decarbonization of the electric grid. One technology with the potential to reduce curtailment is energy storage, and some power producers envision a role for hydrogen to supplement natural gas as a fuel to support the balancing and reliability of an increasingly decarbonized electric grid.

Hydrogen is a zero-GHG emitting fuel when combusted, so that co-firing it in a combustion turbine in place of natural gas reduces GHG emissions at the stack. For this reason, certain owners/operators of combustion turbines in the power sector may elect to co-fire hydrogen in the coming years to reduce onsite GHG emissions.[853] Co-firing low-emitting fuels—sometimes referred to as clean fuels—is a traditional type of emissions control. However, the EPA recognizes that even though the *combustion* of hydrogen is zero-GHG emitting, its *production* can entail a range of GHG emissions, from low to high, depending on the method. These differences in GHG emissions from the different methods of hydrogen production are well-recognized in the energy sector (88 FR 33306, May 23, 2023), and, in fact, hydrogen is generally characterized by its production method and the attendant level of GHG emissions.

While the focus of this rule is the reduction of stack GHG emissions from combustion turbines, the EPA also recognizes that, to ensure overall GHG benefits, it is important any hydrogen used in the power sector be low-GHG hydrogen. Thus, even though the EPA is not finalizing the use of low-GHG hydrogen as a component of the BSER for base load or intermediate load combustion turbines, it maintains that the type of hydrogen used (*i.e.,* the method by which the hydrogen was produced) should be a primary consideration for any source that decides to co-fire hydrogen. Again, the Agency reiterates its concern that sources in the power sector that choose to co-fire hydrogen to reduce their GHG emission rate should co-fire only low-GHG hydrogen to achieve overall GHG reductions and important climate benefits.

In the proposal, the EPA solicited comment on whether it is necessary to require low-GHG hydrogen. Similarly, the EPA also solicited comment as to whether the low-GHG hydrogen requirement could be treated as severable from the remainder of the standard such that the standard could function without this requirement. The EPA also solicited comment on a host of recordkeeping and reporting topics. These pertained to the complexities of tracking the sources of quantities of produced low-GHG hydrogen and the public interest in such data.

a. Explanation for Not Requiring Hydrogen Used for Compliance To Be Low-GHG Hydrogen

The EPA proposed that the type of hydrogen co-fired must be limited to low-GHG hydrogen, and not include other types of hydrogen.[854] This requirement was proposed to prevent the anomalous outcome of a GHG control strategy contributing to an increase in overall GHG emissions; the provision that only low-GHG hydrogen could be used for compliance mirrored the EPA's proposal that low-GHG hydrogen, in particular, could qualify as a component of the BSER. For the reasons explained below, the EPA is not finalizing a requirement that any hydrogen that sources choose to co-fire must be low-GHG hydrogen. However, the Agency continues to stress, notwithstanding the lack of requirement under this rule, the importance of ensuring that any hydrogen used in combustion turbines is low-GHG hydrogen. The EPA's choice to not finalize a low-GHG requirement at this time is based in large part on knowledge of current and future efforts that will reinforce the availability and role of low-GHG hydrogen in the national economy and, more specifically, in the power sector. As discussed further below, this decision is against the backdrop of ongoing developments in the public and private sectors, Treasury's regulations implementing a tax credit for the production of clean hydrogen, multiple Federal government grant and assistance programs, and the EPA's investigation into methods to control emissions of air pollutants from hydrogen production.

The EPA's decision to not require that any hydrogen used for compliance be low-GHG hydrogen was based primarily on the current market and policy developments regarding hydrogen production at this particular point in time, including the clean hydrogen production tax credits. There are currently multiple private and public efforts to develop, *inter alia,* greenhouse gas accounting practices, verification protocols, reporting conventions, and other elements that will help determine how low-GHG hydrogen is measured, tracked, and verified over the next several years. For example, Treasury is expected to finalize parameters for evaluating overall emissions associated with hydrogen production pathways as it prepares to implement IRC section 45V.[855] The overall objective of Treasury's parameters is to recognize that different methods of hydrogen production generate different amounts of GHG emissions while encouraging lower-emitting production methods through the multi-tier hydrogen production tax credit (IRC section 45V) (see 88 FR 89220, December 26, 2023). In light of these nascent but fast-moving efforts, the EPA does not believe it is reasonable or helpful to prescribe its own definitions, protocols, and requirements for low-GHG hydrogen at this point in time.

Furthermore, the Agency anticipates that combustion turbines will, despite not being required to do so, use low-GHG hydrogen (to the extent they are co-firing hydrogen as a compliance strategy). Depending on market development in the coming decade, it is reasonable to expect that any hydrogen used in the power sector would generally be low-GHG hydrogen, even without a specific BSER pathway or low-GHG-only requirement included in this final NSPS. For example, several utilities with dedicated access to affordable low-GHG hydrogen are actively developing co-firing projects with the goal of reducing their GHG

Insight. *https://www.hydrogeninsight.com/electrolysers/what-gives-bill-gates-backed-start-up-electric-hydrogen-the-edge-over-other-electrolyser-makers-/2-1-1572694.*

[853] In June 2022, the U.S. Department of Energy (DOE) Loans Program Office issued a $504.4 million loan guarantee to finance the Advanced Clean Energy Storage (ACES) project in Delta, Utah. ACES expects to utilize a 220 MW bank of electrolyzers and curtailed renewable energy to produce clean hydrogen that will be stored in salt caverns. The hydrogen will fuel an 840 MW combined cycle combustion turbine at the Intermountain Power Project facility. *https://www.energy.gov/lpo/advanced-clean-energy-storage.*

[854] 88 FR 33240, 33315 (May 23, 2023).

[855] U.S. Department of the Treasury. (October 5, 2022). Treasury Seeks Public Input on Implementing the Inflation Reduction Act's Clean Energy Tax Incentives. Press release. *https://home.treasury.gov/news/press-releases/jy0993.*

emissions. The infrastructure funding and tax incentives included in the IIJA and the IRA are also driving the development of the low-GHG hydrogen supply chain. These rapid changes in the hydrogen marketplace not only counsel against the EPA's locking in its own requirements at this time; they also provide confidence that greater quantities of low-GHG hydrogen will be available moving forward, even if the precise timing and quantity cannot currently be accurately forecast. The EPA also provides information further below about its intentions to open a non-regulatory docket to engage stakeholders on potential future rulemakings for thermochemical-based hydrogen production facilities to address issues pertaining to GHG, criteria, and HAP emissions.

i. Hydrogen Production and Associated GHGs

Hydrogen is used in industrial processes; in recent years, applications of hydrogen co-firing have also expanded to include stationary combustion turbines used to generate electricity. Several commenters responded to the proposal by stating that to fully evaluate the potential GHG emission reductions from co-firing low-GHG hydrogen in a combustion turbine EGU, it is important to consider the different processes for producing hydrogen and the GHG emissions associated with each process. The EPA agrees that the method of hydrogen production is critical to consider when assessing whether hydrogen co-firing actually reduces overall GHG emissions. As stated previously, the varying levels of CO_2 emissions associated with different hydrogen production processes are well-recognized, and stakeholders routinely refer to hydrogen on the basis of the different production processes and their different GHG profiles.

ii. Technological and Market Transformation of Low-GHG Hydrogen Resources

In the proposal, the EPA highlighted ongoing efforts—independent of any BSER pathway, requirement, or performance standard—of combustion turbine manufacturers and industry stakeholders to research, develop, and deploy hydrogen co-firing technologies (88 FR 33307, May 23, 2023). Their co-firing demonstrations are producing results, such as increasing the percentages (by volume) of hydrogen that a turbine can combust while answering questions regarding safety, performance, reliability, durability, and the emission of other pollutants (*e.g.,* NO_X). Such efforts by industry to invest in the development of hydrogen co-firing, and specifically in projects designed to co-fire low-GHG hydrogen, in particular, give the EPA confidence that any hydrogen that sources do choose to co-fire for compliance under this rule will be low-GHG hydrogen. As these efforts progress, a sharper understanding of costs will come into focus while significant Federal funding—through grants, financial assistance programs, and tax incentives included in the IIJA and the IRA discussed below—is intended to support the continued development of a nationwide clean hydrogen supply chain.

For the most part, companies that have announced that they are exploring the use of hydrogen co-firing have stated that they intend to use low-GHG hydrogen in the future as greater quantities of the fuel become available at lower, stabilized prices. Many utilities and merchant generators own and are developing low-GHG electricity generating sources as well as combustion turbines, with the intent to produce low-GHG hydrogen for sale and to use a portion of it to fuel their stationary combustion turbines.[856] [857] This emerging trend lends support to the view that, while acknowledging the uncertainty of the ultimate timing of implementation, there is growing interest in hydrogen co-firing in the power sector and stakeholders are developing these resources with the intent to increase access to low-GHG hydrogen as they increase hydrogen utilization in their co-firing applications. Additional information provided by commenters and analysis by the EPA identified several new combustion turbine projects planning to co-fire low-GHG hydrogen, even though these low-GHG methods of hydrogen production are not currently readily available on a nationwide basis.[858] [859] [860]

iii. Infrastructure Funding and Tax Incentives Included in the IIJA and IRA

In both the IIJA and the IRA, Congress provided extensive support for the development of hydrogen produced through low-GHG methods. This support includes investment in infrastructure through the IIJA, and the provision of tax credits in the IRA to incentivize the manufacture of hydrogen through low GHG-emitting methods over the coming decades. For example, the IIJA included the H2Hubs program, the Clean Hydrogen Manufacturing and Recycling Program, the Clean Hydrogen Electrolysis Program, and a non-regulatory Clean Hydrogen Production Standard (CHPS).[861] In the IRA, Congress enacted or expanded tax credits to encourage the production and use of low-GHG hydrogen.[862] In addition, as discussed in the proposal, IRA section 60107 added new CAA section 135, or the Low Emission Electricity Program (LEEP). This provision provides $1 million for the EPA to assess the GHG emissions reductions from changes in domestic electricity generation and use anticipated to occur annually through fiscal year 2031; and further provides $18 million for the EPA to promulgate additional CAA rules to ensure GHG emissions reductions that go beyond the reductions expected in that assessment. CAA section 135(a)(5)–(6).

Given the incentives provided in both the IRA and IIJA for low-GHG hydrogen production and the current trajectory of hydrogen use in the power sector, by 2032, the start date for compliance with the proposed second phase of the NSPS, low-GHG hydrogen may be more widely available and possibly the most common source of hydrogen available for electricity production. It is also possible that the cost of delivered low-GHG hydrogen will continue to decline toward the DOE's Hydrogen Shot target. These expectations are based on a combination of economies of scale as low-GHG production methods expand, the increasing availability of low-cost input electricity—largely powered by zero- or low-emitting energy sources—

[856] Mitsubishi Power. (2020). *Intermountain Power Agency Orders MHPS JAC Gas Turbine Technology for Renewable-Hydrogen Energy Hub. https://power.mhi.com/regions/amer/news/200310.html.*

[857] Intermountain Power Agency (2022). *https://www.ipautah.com/ipp-renewed/.*

[858] Los Angeles Department of Water & Power (2023*). Initial Study: Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project. https://ceqanet.opr.ca.gov/2023050366.*

[859] *https://clkrep.lacity.org/onlinedocs/2023/23-0039_rpt_DWP_02-03-2023.pdf.*

[860] Hering, G. (2021). First major US hydrogen-burning power plant nears completion in Ohio. *S&P Global Market Intelligence. https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081221-first-major-us-hydrogen-burning-power-plant-nears-completion-in-ohio.*

[861] U.S. Department of Energy (DOE). (September 22, 2022). Clean Hydrogen Production Standard. Hydrogen and Fuel Cell Technologies Office. *https://www.energy.gov/eere/fuelcells/articles/clean-hydrogen-production-standard.*

[862] These tax credits include IRC section 45V (tax credit for production of hydrogen through low- or zero-emitting processes), IRC section 48 (tax credit for investment in energy storage property, including hydrogen production), IRC section 45Q (tax credit for CO_2 sequestration from industrial processes, including hydrogen production); and the use of hydrogen in transportation applications, IRC section 45Z (clean fuel production tax credit), IRC section 40B (sustainable aviation fuel credit).

and learning by doing as more combustion turbine projects are developed. The EPA recognizes that the pace and scale of government programs and private research suggest that the Agency will gain significant experience and knowledge on this topic in the future.

iv. EPA Non-Regulatory Docket and Stakeholder Engagement on Potential Regulatory Approaches for Emissions From Thermochemical Hydrogen Production

In addition to the ongoing industry development of and Congressional support for low-GHG hydrogen, the EPA is also taking steps consistent with the importance of mitigating GHG emissions associated with hydrogen production. On September 15, 2023, the EPA received a petition from the Environmental Defense Fund (EDF) along with 13 other health, environmental, and community groups, to regulate fossil and other thermochemical methods of hydrogen production given the current emissions from these facilities and the anticipated growth in the sector spurred by IRA incentives. The petition notes that facilities producing hydrogen for sale produced about 10 MMT of hydrogen and emitted more than 40 MMT of CO_2e in 2020.[863] Regulatory safeguards are advocated by petitioners to help ensure that the anticipated growth in this sector does not result in an unbounded increase in emissions of GHGs, criteria, and hazardous air pollutants (HAP). The petition requests that the EPA list hydrogen production facilities as significant sources of pollution under CAA sections 111 and 112, and that the EPA develop both standards of performance for new and modified hydrogen production facilities as well as emission guidelines for existing facilities. The development of emission standards for HAP, including but not limited to methanol, was also requested by petitioners. Petitioners assert that emissions of CO_2, NO_X, and PM should be addressed under the EPA's section 111 authorities, and HAP should be addressed by EPA regulations under section 112.[864] The EPA is reviewing the petition. As a predicate to potential future rulemakings, the Agency is developing a set of framing questions and opening a non-regulatory docket to solicit public comment on potential approaches for regulation of GHGs and criteria pollutants under CAA section 111 and an exploration of the appropriateness of regulating HAP emissions under CAA section 112 and on potential section 114 reporting requirements to address this growing industry.

b. Definition of Low-GHG Hydrogen

The EPA proposed to define low-GHG hydrogen as hydrogen produced with emissions of less than 0.45 kg CO_2e/kg H_2, from well-to-gate, which aligned with the highest of the four tiers of tax credits available for hydrogen production, IRC section 45V(b)(2)(D). At that GHG emission rate or less, hydrogen producers are eligible for a tax credit of $3/kg. With these provisions, Congress indicated its judgement as to what GHG levels could be attained by the lowest-GHG hydrogen production, and its intention to incentivize production of that type of hydrogen. Congress's views informed the EPA's proposal to define low-GHG hydrogen for purposes of making the BSER for this CAA section 111 rulemaking consistent with IRC section 45V(b)(2)(D).

The EPA solicited comment broadly on its proposed definition for low-GHG hydrogen, and on alternative approaches, to help develop reporting and recordkeeping requirements that would have ensured that co-firing low-GHG hydrogen minimized GHG emissions, and that combustion turbines subject to this standard utilized only low-GHG hydrogen. The EPA also solicited comment on whether it was necessary to provide a definition of low-GHG hydrogen in this final rule.

The EPA is not finalizing a definition of low-GHG hydrogen in this action. Because the Agency is not finalizing co-firing with low-GHG hydrogen as a component of the BSER for certain combustion turbines and is not finalizing a requirement that any hydrogen co-fired for compliance by low-GHG hydrogen, there is no reason to finalize a definition of low-GHG hydrogen at this time.

7. Other Options for BSER

The EPA considered several other systems of emission reduction as candidates for the BSER for combustion turbines but is not determining them to be the BSER. They include partial capture CCS, CHP and the hybrid power plant, as discussed below.

a. Partial Capture CCS

Partial capture for CCS was not determined to be BSER because the emission reductions are lower and the costs would, in general, be higher. As discussed in section IV, individual natural gas-fired combined cycle combustion turbines are the second highest-emitting individual plants in the nation, and the natural gas-fired power plant sector is higher-emitting than all other sectors. CCS at 90 percent capture removes very high absolute amounts of emissions. Partial capture CCS would fail to capture large quantities of emissions. With respect to costs, designs for 90 percent capture in general take greater advantage of economy of scale. Eligibility for the IRC section 45Q tax credit for existing EGUs requires design capture rates equivalent to 75 percent of a baseline emission rate by mass. Sources with partial capture rates that do not meet that requirement would not be eligible for the tax credit and as a result, for them, the CCS requirement would be too expensive to qualify for as the BSER. Even assuming partial capture rates meet that definition, lower capture rates would receive fewer returns from the IRC section 45Q tax credit (since these are tied to the amount of carbon sequestered, and all else equal lower capture rates would result in lower amounts of sequestered carbon) and costs would thereby be higher.

b. Combined Heat and Power (CHP)

CHP, also known as cogeneration, is the simultaneous production of electricity and/or mechanical energy and useful thermal output from a single fuel. CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP has lower-emission rates and can be more economic than separate electric and thermal generation. However, a critical requirement for a CHP facility is that it primarily generates thermal output and generates electricity as a byproduct and must therefore be physically close to a thermal host that can consistently accept the useful thermal output. It can be particularly difficult to locate a thermal host with sufficiently large thermal demands such that the useful thermal output would impact the emissions rate. The refining, chemical manufacturing, pulp and paper, food processing, and district energy systems tend to have large thermal demands. However, the thermal demand at these facilities is generally only sufficient to support a smaller EGU, approximately a maximum of several hundred MW. This

[863] Petition for Rulemaking to List and Establish National Emission Standards for Hydrogen Production Facilities under the Clean Air Act Sections 111 and 112. The petition can be accessed at *https://www.edf.org/sites/default/files/2023-09/Petition%20for%20Rulemaking%20-%20Hydrogen%20Production%20Facilities%20-%20CAA%20111%20and%20112%20-%20EDF%20et%20al.pdf.*

[864] *Id.*

would limit the geographically available locations where new generation could be constructed in addition to limiting its size. Furthermore, even if a sufficiently large thermal host were in close proximity, the owner/operator of the EGU would be required to rely on the continued operation of the thermal host for the life of the EGU. If the thermal host were to shut down, the EGU could be unable to comply with the standard of performance. This reality would likely result in difficulty in securing funding for the construction of the EGU and could also lead the thermal host to demand discount pricing for the delivered useful thermal output. For these reasons, the EPA did not propose CHP as the BSER.

c. Hybrid Power Plant

Hybrid power plants combine two or more forms of energy input into a single facility with an integrated mix of complementary generation methods. While there are multiple types of hybrid power plants, the most relevant type for this proposal is the integration of solar energy (*e.g.,* concentrating solar thermal) with a fossil fuel-fired EGU. Both coal-fired and combined cycle turbine EGUs have operated using the integration of concentrating solar thermal energy for use in boiler feed water heating, preheating makeup water, and/or producing steam for use in the steam turbine or to power the boiler feed pumps.

One of the benefits of integrating solar thermal with a fossil fuel-fired EGU is the lower capital and operation and maintenance (O&M) costs of the solar thermal technology. This is due to the ability to use equipment (*e.g.,* HRSG, steam turbine, condenser, *etc.*) already included at the fossil fuel-fired EGU. Another advantage is the improved electrical generation efficiency of the non-emitting generation. For example, solar thermal often produces steam at relatively low temperatures and pressures, and the conversion of the thermal energy in the steam to electricity is relatively low efficiency. In a hybrid power plant, the lower quality steam is heated to higher temperatures and pressures in the boiler (or HRSG) prior to expansion in the steam turbine, where it produces electricity. Upgrading the relatively low-grade steam produced by the solar thermal facility in the boiler improves the relative conversion efficiencies of the solar thermal to electricity process. The primary incremental costs of the non-emitting generation in a hybrid power plant are the costs of the mirrors, additional piping, and a steam turbine that is 10 to 20 percent larger than that in a comparable fossil-only EGU to accommodate the additional steam load during sunny hours. A drawback of integrating solar thermal is that the larger steam turbine will operate at part loads and reduced efficiency when no steam is provided from the solar thermal panels (*i.e.,* the night and cloudy weather). This limits the amount of solar thermal that can be integrated into the steam cycle at a fossil fuel-fired EGU.

In the 2018 Annual Energy Outlook,[865] the levelized cost of concentrated solar power (CSP) without transmission costs or tax credits is $161/MWh. Integrating solar thermal into a fossil fuel-fired EGU reduces the capital cost and O&M expenses of the CSP portion by 25 and 67 percent compared to a stand-alone CSP EGU respectively.[866] This results in an effective LCOE for the integrated CSP of $104/MWh. Assuming the integrated CSP is sized to provide 10 percent of the maximum steam turbine output and the relative capacity factors of a combined cycle turbine and the CSP (those capacity factors are 65 and 25 percent, respectively) the overall annual generation due to the concentrating solar thermal would be 3 percent of the hybrid EGU output. This would result in a 3 percent reduction in the overall CO_2 emissions and a 1 percent increase in the LCOE, without accounting for any reduction in the steam turbine efficiency. However, these costs do not account for potential reductions in the steam turbine efficiency due to being oversized relative to a non-hybrid EGU. A 2011 technical report by the National Renewable Energy Laboratory (NREL) cited analyses indicating that solar augmentation of fossil power stations is not cost-effective, although likely less expensive and containing less project risk than a stand-alone solar thermal plant. Similarly, while commenters stated that solar augmentation has been successfully integrated at coal-fired plants to improve overall unit efficiency, commenters did not provide any new information on costs or indicate that such augmentation is cost-effective.

In addition, solar thermal facilities require locations with abundant sunshine and significant land area in order to collect the thermal energy. Existing concentrated solar power projects in the U.S. are primarily located in California, Arizona, and Nevada with smaller projects in Florida, Hawaii, Utah, and Colorado. NREL's 2011 technical report on the solar-augment potential of fossil-fired power plants examined regions of the U.S. with ''good solar resource as defined by their direct normal insolation (DNI)'' and identified sixteen states as meeting that criterion: Alabama, Arizona, California, Colorado, Florida, Georgia, Louisiana, Mississippi, Nevada, New Mexico, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, and Utah. The technical report explained that annual average DNI has a significant effect on the performance of a solar-augmented fossil plant, with higher average DNI translating into the ability of a hybrid power plant to produce more steam for augmenting the plant. The technical report used a points-based system and assigned the most points for high solar resource values. An examination of a NREL-generated DNI map of the U.S. reveals that states with the highest DNI values are located in the southwestern U.S., with only portions of Arizona, California, Nevada, New Mexico, and Texas (plus Hawaii) having solar resources that would have been assigned the highest points by the NREL technical report (7 kWh/m2/day or greater).

Commenters supported not incorporating hybrid power plants as part of the BSER, and the EPA is not including hybrid power plants as part of the BSER because of gaps in the EPA's knowledge about costs, and concerns about the cost-effectiveness of the technology, as noted above.

G. Standards of Performance

Once the EPA has determined that a particular system or technology represents BSER, the CAA authorizes the Administrator to establish standards of performance for new units that reflect the degree of emission limitation achievable through the application of that BSER. As noted above, the EPA is finalizing a two-phase set of standards of performance, which reflect a two-component BSER, for base load combustion turbines. Under this approach, for the first phase of the standards, which applies as of the effective date the final rule, the BSER is highly efficient generation and best operating and maintenance practices. During this phase, owners/operators of EGUs will be subject to a numeric standard of performance that is representative of the performance of the best performing EGUs in the subcategory. For the second phase of the standards, beginning in 2035, the BSER for base load turbines includes 90

[865] EIA, Annual Energy Outlook 2018, February 6, 2018. *https://www.eia.gov/outlooks/aeo/.*

[866] B. Alqahtani and D. Patiño-Echeverri, Duke University, Nicholas School of the Environment, ''Integrated Solar Combined Cycle Power Plants: Paving the Way for Thermal Solar,'' Applied Energy 169:927–936 (2016).

percent capture CCS. The affected EGUs will be subject to an emissions rate that reflects continued use of highly efficient generation and best operating and maintenance practices, coupled with CCS. In addition, the EPA is finalizing a single component BSER, applicable from May 23, 2023, for low and intermediate load combustion turbines.

1. Phase-1 Standards

The first component of the BSER is the use of highly efficient combined cycle technology for base load EGUs in combination with the best operating and maintenance practices, the use of highly efficient simple cycle technology in combination with the best operating and maintenance practices for intermediate load EGUs, and the use of lower-emitting fuels for low load EGUs.

The EPA proposed that for base load combustion turbines, the first-component BSER supports a standard of 770 lb CO_2/MWh-gross for large natural gas-fired EGUs, *i.e.,* those with a base load rating heat input greater than 2,000 MMBtu/h; 900 lb CO_2/MWh-gross for small natural gas-fired EGUs, *i.e.,* those with a base load rating of 250 MMBtu/h; and between 900 and 770 lb CO_2/MWh-gross, based on the base load rating of the EGU, for natural gas-fired EGUs with base load ratings between 250 MMBtu/h and 2,000 MMBtu/h.[867] The EPA proposed that the most efficient available simple cycle technology—which qualifies as the BSER for intermediate load combustion turbines—supports a standard of 1,150 lb CO_2/MWh-gross for natural gas-fired EGUs. For new and reconstructed low load combustion turbines, the EPA proposed to find that the use of lower-emitting fuels—which qualifies as the BSER—supports a standard that ranges from 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu depending on the fuel burned. The EPA proposed these standards to apply at all times and compliance to be determined on a 12-operating month rolling average basis.

The EPA proposed that these standards of performance are achievable specifically for natural gas-fired base load and intermediate load combustion turbine EGUs. However, combustion turbine EGUs burn a variety of fuels, including fuel oil during natural gas curtailments. Owners/operators of combustion turbines burning fuels other than natural gas would not necessarily be able to comply with the proposed standards for base load and intermediate load natural gas-fired combustion turbines using highly efficient generation. Therefore, the Agency proposed that owners/operators of combustion turbines burning fuels other than natural gas may elect to use the ratio of the heat input-based emissions rate of the specific fuel(s) burned to the heat input-based emissions rate of natural gas to determine a source-specific standard of performance for the operating period. For example, the NSPS emissions rate for a large base load combustion turbine burning 100 percent distillate oil during the 12-operating month period would be 1,070 lb CO_2/MWh-gross.[868]

Some commenters stated that the proposed base load emissions standard based on highly efficient generation is not adequately demonstrated, and that site conditions and certain operating parameters are outside of the control of the owner/operator. These commenters explained that the emissions rate of a combustion turbine is dependent on external and site-specific factors, rather than the design efficiency. Factors such as warmer climates, elevation, water conservation measures (*e.g.,* the use of dry cooling), and automatic generation control negatively impacted efficiency. They emphasized that operating units at partial loads would be necessary for maintaining grid reliability, especially as more renewables are incorporated, and the proposed limit is only achievable under ideal operating conditions. Commenters noted that the emission standards should account for start and stop cycles, back-up fuel use, degradation, and compliance tolerance. Commenters stated that the lack of flexibility would force units to operate at nameplate capacity, even when it was unnecessary and could result in increased emissions. In addition, some commenters stated that duct burners could be an alternative to simple cycle turbines for peaking generation, even though they were less efficient than combined cycle turbines without duct burners. They recommended the Agency consider excluding emissions and heat input from duct burners from the emissions standard. Furthermore, commenters noted multiple units that the EPA used in the analysis to support the proposed base load standards were permitted near or above 800 lb CO_2/MWh. Commenters stated that the original equipment manufacturer would not be able to provide a warranty that the proposed 12-month rolling emissions rate is achievable due to the varying operating conditions. Commenters recommended the EPA raise the emissions standard to 850 or 900 lb CO_2/MWh-gross for large base load combustion turbines. In addition, commenters suggested that the EPA incorporate scaling for smaller units to 1,100 lb CO_2/MWh-gross, and the beginning of the sliding scale should be at least 2,500 MMBtu/h.

a. Base Load Phase-1 Emission Standards

Considering the public comments, the EPA re-evaluated the phase-1 standard of performance for base load combustion turbines. To determine the impact of duty cycle and temperature, the EPA binned hourly data by load and season. This allowed the Agency to isolate the impact of ambient temperature and duty cycle separately. The EPA evaluated the impact of ambient temperature by comparing the average emissions for all hours between 70 to 80 percent load during different seasons. For the combined cycle turbines evaluated, the difference between the summer and winter average emission rates was minimal, typically in the single digits and less than a 1 percent difference in emission rates. Since the seasonal temperature differences are much larger than regional variations, the EPA determined that regional ambient temperature has minimal impact on the emissions rate of combined cycle EGUs. Owners/operators of combined cycle EGUs are either using inlet cooling effectively to manage the efficiency losses of the combustion turbine engine or increased generation from the Rankine cycle portion (*i.e.,* HRSG and steam turbine) of the combined cycle turbine is offsetting efficiency losses in the combustion turbine engine.[869] In addition, the variation in emissions rate by load (described below) is much larger than temperature and therefore the operating load is a more important factor than ambient temperature impacting CO_2 emission rates.

Based on the emissions data submitted to the EPA, combined cycle

[867] As proposed, a new small natural gas-fired base load EGU would determine the facility emissions rate by taking the difference in the base load rating and 250 MMBtu/h, multiplying that number by 0.0743 lb CO_2/(MW * MMBtu), and subtracting that number from 900 lb CO_2/MWh-gross. The emissions rate for a natural gas-fired base load combustion turbine with a base load rating of 1,000 MMBtu/h is 900 lb CO_2/MWh-gross minus 750 MMBtu/h (1,000 MMBtu/h–250 MMBtu/h) times 0.0743 lb CO_2/(MW * MMBtu), which results in an emissions rate of 844 lb CO_2/MWh-gross.

[868] The heat input-based emission rates of natural gas and distillate oil are 117 and 163 lb CO_2/MMBtu, respectively. The ratio of the heat input-based emission rates (1.39) is multiplied by the natural gas-fired standard of performance (770 lb CO_2/MWh) to get the applicable emissions rate (1,070 lb CO_2/MWh).

[869] As the efficiency of the combustion turbine engine is reduced at higher ambient temperatures relatively more heat is in the exhaust entering the HRSG. This can increase the output from the steam turbine.

CO_2 emission are lowest at between approximately 80 to 90 percent load. Emission rates are relatively stable at higher loads and down to approximately 70 percent load—typically 1 or 2 percent higher than the lowest emissions rate. Emissions can increase dramatically at lower loads and could impact the ability of an owner/operator to comply with the base load standard. The EPA considered two approaches to address potential compliance issues for owners/operators of base load combustion turbines operating at lower duty cycles. The first approach was to calculate emission rates using only hourly data when the combined cycle turbine was operating at an hourly load of 70 percent or higher. However, this has minimal impact on the calculated base load emissions rate. This is because of 2 reasons. First, the majority of operating hours for base load combustion turbines are at 70 percent load or higher. In addition, the 12-operating month averages are determined by the overall sum of the CO_2 emissions divided by the overall output during the 12-operating month period and not the average of the individual hourly rates. The impact of this approach is that low load hours have smaller impacts on the 12-operating month average relative to high load hours. Therefore, the EPA determined that using only higher load hours to determine the base load emission rates would not address potential issues for owners/operators of base load combustion turbines operating at relative low duty cycles (*i.e.,* low hourly capacity factors).

The second approach the EPA considered, and is finalizing, is estimating the emissions rate of combined cycle turbines at the lower end of the base load threshold—where more hours of low load operation could potentially be included in the 12-operating month average—and establishing a standard of performance that is achievable at lower percent of potential electric sales for the base load subcategory. To determine what emission rates are currently achieved by existing high-efficiency combined cycle EGUs, the EPA reviewed 12-operating month generation and CO_2 emissions data from 2015 through 2023 for all combined cycle turbines that submitted continuous emissions monitoring system (CEMS) data to the EPA's emissions collection and monitoring plan system (ECMPS). The data were sorted by the lowest maximum 12-operating month emissions rate for each unit to identify long-term emission rates on a lb CO_2/MWh-gross basis that have been demonstrated by the existing combined cycle EGU fleets. Since an NSPS is a never-to-exceed standard, the EPA proposed and is finalizing a conclusion that use of long-term data are more appropriate than shorter term data in determining an achievable standard. These long-term averages account for degradation and variable operating conditions, and the EGUs should be able to maintain their current emission rates, as long as the units are properly maintained. While annual emission rates indicate a particular standard is achievable for certain EGUs in the short term, they are not necessarily representative of emission rates that can be maintained over an extended period using highly efficient generating technology in combination with best operating and maintenance practices.

To determine the 12-operating month average emissions rate that is achievable by application of the BSER, the EPA proposed and is finalizing an approach to calculating 12-month CO_2 emission rates by dividing the sum of the CO_2 emissions by the sum of the gross electrical energy output over the same period. The EPA did this separately for combined cycle EGUs and simple cycle EGUs to determine the emissions rate for the base load and intermediate load subcategories, respectively. Commenters generally supported the 12-month rolling average for emission standard compliance.

The average maximum 12-operating month base load emissions rate for large combined cycle turbines that began operation since 2015 is 810 lb CO_2/MWh-gross. The range of the maximum 12-operating month emissions rate for individual units is 720 to 920 lb CO_2/MWh-gross. The lowest emissions rate was achieved by an individual unit at the Okeechobee Clean Energy Center. This facility is a large 3-on-1 combined cycle EGU that commenced operation in 2019 and uses a recirculating cooling tower for the steam cycle. Each turbine is rated at 380 MW and the three HRSGs feed a single steam turbine of 550 MW. The EPA did not propose to use the emissions rate of this EGU to determine the standard of performance for multiple reasons. The Okeechobee Clean Energy Center uses a 3-on-1 multi-shaft configuration but, many combined cycle EGUs use a 1-on-1 configuration. Combined cycle EGUs using a 1-on-1 configuration can be designed such that both the combustion turbine and steam turbine are arranged on one shaft and drive the same generator. This configuration has potential capital cost and maintenance costs savings and a smaller plant footprint that can be particularly important for combustion turbines enclosed in a building. In addition, a single shaft configuration has higher net efficiencies when operated at part load than a multi-shaft configuration. Basing the standard of performance strictly on the performance of multi-shaft combined cycle EGUs could limit the ability of owners/operators to construct new combined cycle EGUs in space-constrained areas (typically urban areas[870]) and combined cycle EGUs with the best performance when operated as intermediate load EGUs.[871] Either of these outcomes could result in greater overall emissions from the power sector. An advantage of multi-shaft configurations is that the turbine engine can be installed initially and run as a simple cycle EGU, with the HRSG and steam turbines added at a later date, all of which allows for more flexibility for the regulated community. In addition, a single large steam turbine in a 2–1 or 3–1 configuration can generate electricity more efficiently than multiple smaller steam turbines, increasing the overall efficiency of comparably sized combined cycle EGUs. According to Gas Turbine World 2021, multi-shaft combined cycle EGUs have design efficiencies that are 0.7 percent higher than single shaft combined cycle EGUs using the same turbine engine.[872]

The efficiency of the Rankine cycle (*i.e.,* HRSG plus the steam turbine) is determined in part by the ability to cool the working fluid (*e.g.,* steam) after it has been expanded through the turbine. All else equal, the lower the temperature that can be achieved, the more efficient the Rankine cycle. The Okeechobee Clean Energy Center used a recirculating cooling system, which can achieve lower temperatures than EGUs using dry cooling systems and therefore would be more efficient and have a lower emissions rate. However dry cooling systems have lower water requirements and therefore could be the preferred technology in arid regions or

[870] Generating electricity closer to electricity demand can reduce stress on the electric grid, reducing line losses and freeing up transmission capacity to support additional generation from variable renewable sources. Further, combined cycle EGUs located in urban areas could be designed as CHP EGUs, which have potential environmental and economic benefits.

[871] Power sector modeling projects that combined cycle EGUs will operate at lower capacity factors in the future. Combined cycle EGUs with lower base load efficiencies but higher part load efficiencies could have lower overall emission rates.

[872] According to the data in Gas Turbine World 2021, while there is a design efficiency advantage of going from a 1-on-1 configuration to a 2-on-1 configuration (assuming the same turbine engine), there is no efficiency advantage of 3-on-1 configurations compared to 2-on-1 configurations.

in areas where water requirements could have significant ecological impacts. Therefore, the EPA proposed and is finalizing that the efficient generation standard for base load EGUs should account for the use of cooling technologies with reduced water requirements.

Finally, the Okeechobee Clean Energy Center operates primarily at high duty cycles where efficiency is the highest and since it is a relatively new facility efficiency degradation might not be accounted for in the emissions analysis. Therefore, the EPA is not determining that the performance of the Okeechobee Clean Energy Facility is appropriate for a nationwide standard.

The proposed emissions rate of 770 lb CO_2/MWh-gross has been demonstrated by approximately 15 percent of recently constructed large combined cycle EGUs. As noted in the proposal, these combustion turbines include combined cycle EGUs using 1-on-1 configurations, dry cooling, and combustion turbines on the lower end of the large base load subcategory. In addition, this emissions rate has been demonstrated by using combustion turbines from multiple manufacturers and from one facility that commenced operation in 2011—demonstrating the long-term achievability of the proposed emissions standard. However, as noted by commenters the majority of recently constructed combined cycle turbines are not achieving an emissions rate of 770 lb CO_2/MWh-gross and combustion turbine manufacturers might not be willing to guarantee this emissions level in operating making it challenging to build a new combined cycle EGU.

To account for differences in the performance of the best performing combustion turbines and design options that result in less efficient operation, the EPA normalized the reported emission rates for combined cycle EGUs.[873] Specifically, for the reported emissions rates of combined cycle turbines with cooling towers was increased by 1.0 percent to account for potential new units using dry cooling. Similarly, the emissions rate of 2–1 and 3–1 combined cycle turbines were increased by 1.4 percent to account for potential new units using a 1–1 configuration. In addition, for the best performing combined cycle turbines, the EPA plotted the 12-operating month emissions rate against the 12-operating month heat input-based capacity factor. Based on this data, the EPA used the trend in increasing emission rates at lower 12-operating month capacity factors to estimate the emissions rate at capacity factors at which an individual facility has never operated. This approach allowed the EPA to estimate the emissions rate at a 40 percent 12-operating month capacity factor for the best performing combined cycle turbines. This allows the estimation of the emissions rate at the lower end of the base load subcategory using higher capacity factor data.[874] The EPA did not correct the achievable emissions rate for combined cycle turbines where the relationship indicated emission rates declined at lower 12-operating month capacity factors.

As noted in the proposal, one of the best performing large combined cycle EGUs that has maintained a 12-operating-month base load emissions rate of 770 lb CO_2/MWh-gross is the Dresden plant, located in Ohio.[875] This 2-on-1 combined cycle facility uses a recirculating cooling tower. The turbine engines are rated at 2,250 MMBtu/h, which demonstrates that the standard of performance for large base load combustion turbines is achievable at a heat input rating of 2,000 MMBtu/h. As noted, a 2-on-1 configuration and a cooling tower are more efficient than a 1-on-1 configuration and dry cooling. Normalizing for these factors and accounting for operation at a 12-operating month capacity factor of 40 percent increases the achievable demonstrated emissions rate to 800 lb CO_2/MWh-gross. However, the Dresden Energy Facility does not use the most efficient combined cycle design currently available. Multiple more efficient designs have been developed since the Dresden Energy Facility commenced operation a decade ago that more than offset these efficiency losses. Therefore, the EPA has determined that the Dresden combined cycle EGU demonstrates that an emissions rate of 800 lb CO_2/MWh-gross is achievable for all new large combined cycle EGUs with an acceptable compliance margin. Therefore, the EPA is finalizing a phase 1 standard of performance of 800 lb CO_2/MWh-gross for large base load combustion turbines (*i.e.,* those with a base load rating heat input greater than 2,000 MMBtu/h) based on the BSER of highly efficient combined cycle technology.

With respect to small combined cycle combustion turbines, the best performing unit identified by the EPA is the Holland Energy Park facility in Holland, Michigan, which commenced operation in 2017 and uses a 2-on-1 configuration and a cooling tower.[876] The 50 MW turbine engines have individual heat input ratings of 590 MMBtu/h and serve a single 45 MW steam turbine. The facility has maintained a 12-operating month, 99 percent confidence emissions rate of 870 lb CO_2/MWh-gross. The emissions standard for a base load combustion turbine of this size is 880 lb CO_2/MWh-gross. The normalized emissions rate accounting for the use of recirculating cooling towers, a 2–1 configuration, and operation at a 40 percent capacity factor is 900 lb CO_2/MWh-gross. While this is higher than the final emissions standard in this rule, there are efficient generation technologies that are not being used at the Holland Energy Park. For example, a commercially available HRSG that uses supercritical CO_2 instead of steam as the working fluid is available. This HRSG would be significantly more efficient than the HRSG that uses dual pressure steam, which is common for small combined cycle EGUs.[877] When these efficiency improvements are accounted for, a similar combined cycle EGU would be able to maintain an emissions rate of 880 lb CO_2/MWh-gross. In addition, the normalization approach assumes a worst-case scenario. Hybrid cooling technologies are available and offer performance similar to that of wet cooling towers. This long-term data accounts for degradation and variable operating conditions and demonstrates that a base load combustion turbine EGU with a turbine rated at 590 MMBtu/h should be able to maintain an emissions rate of 880 lb CO_2/MWh-gross.[878] Therefore, estimating that

[873] A similar normalization approach was used by the EPA in previous EGU GHG NSPS rulemakings to benchmark the performance of coal-fired EGUs when determining an achievable efficiency-based standard of performance.

[874] The most efficient combined cycle turbines tend to operate strictly as base load combustion turbines, well above the base load subcategorization threshold.

[875] The Dresden Energy Facility is listed as being located in Muskingum County, Ohio, as being owned by the Appalachian Power Company, as having commenced commercial operation in late 2011. The facility ID (ORISPL) is 55350 1A and 1B.

[876] The Holland Park Energy Center is a CHP system that uses hot water in the cooling system for a snow melt system that uses a warm water piping system to heat the downtown sidewalks to clear the snow during the winter. Since this useful thermal output is low temperature, it likely only results in a small reduction of the electrical efficiency of the EGU. If the useful thermal output were accounted for, the emissions rate of the Holland Energy Park would be lower. The facility ID (ORISPL) is 59093 10 and 11.

[877] If the combustion turbine engine exhaust temperature is 500 °C or greater, a HRSG using 3 pressure steam without a reheat cycle could potentially provide an even greater increase in efficiency (relative to a HRSG using 2 pressure steam without a reheat cycle).

[878] To estimate an achievable emissions rate for an efficient combined cycle EGU at 250 MMBtu/h

Continued

emission rates will be slightly higher for smaller combustion turbines, the EPA is finalizing a phase 1 standard of performance of 900 lb CO_2/MWh-gross for small base load combustion turbines (*i.e.,* those with a base load rating of 250 MMBtu/h) based on the BSER of highly efficient combined cycle technology.

b. Intermediate Load Emission Standards

For the intermediate load standards of performance, some commenters stated that an emissions standard of 1,150 lb CO_2/MWh-gross is only achievable for simple cycle except under ideal operating conditions. Since the emissions standard is not achievable in practice, these commenters stated that the majority of new simple cycle turbines would be prevented from operating as variable or intermediate load units. Similar to comments on the base load emissions standard, commenters stated the standard of performance should account for ambient conditions, operation at part load, automatic generation control, and variable loads. If the intermediate load standard is not achievable in practice, it could result in the operation of less efficient generation in other operating modes and an increase in overall GHG emissions. They also explained this could force simple cycle turbines to always operate at nameplate capacity, even when it was not necessary, which would also lead to increased emissions. These commenters requested that the EPA raise the variable and intermediate load emissions standard to 1,250 to 1,300 lb CO_2/MWh-gross.

Considering the public comments, the EPA re-evaluated the standard of performance for intermediate load combustion turbines using the same approach as for combined cycle turbines, except using the performance of simple cycle EGUs. The average maximum 12-operating operating month intermediate load emissions rate for simple cycle turbines that began operation since 2015 is 1,210 lb CO_2/MWh-gross. The range of the maximum 12-operating month emissions rate for individual units is 1,080 to 1,470 lb CO_2/MWh-gross. The lowest emissions rate was achieved by an individual unit at the Scattergood Generating Station. This facility includes 2 large aeroderivative simple cycle turbines (General Electric LMS 100) that commenced operation in 2015. Each turbine is rated at approximately 100 MW and use water injection to reduce NO_X emissions. The EPA did not propose and is not finalizing to use the emissions rate of this EGU to determine the standard of performance for multiple reasons. Simple cycle turbine efficiency tends to increase with size and the simple cycle turbines at the Scattergood Facility are the largest aeroderivative turbines available. Establishing a standard of performance based on emission rates that only large aeroderivative turbines could achieve would limit the ability to develop new firm combustion turbine based generating capacity in smaller than 100 MW increments. This could result in the local electric grid operating in a less overall efficient manner, increasing overall GHG emissions. In addition, the largest available aeroderivative simple cycle turbines can use either water injection or dry low NO_X combustion to reduce emissions of NO_X. For this particular design, the use of water injection has higher design efficiencies than the dry low NO_X option. Water injection has similar ecological impacts as water used for cooling towers, the EPA has determined in this case it is important to preserve the option for new intermediate load combustion turbines to use dry low NO_X combustion.

The proposed emissions rate of 1,150 lb CO_2/MWh-gross was achieved by 20 percent of recently constructed intermediate load simple cycle turbines. However, only two-thirds of LMS 100 simple cycle turbines installed to date have maintained an intermediate load emissions rate of 1,150 lb CO_2/MWh-gross. In addition, only one-third of the Siemens STG–A65 simple cycle turbines and only 10 percent of General Electric LM6000 simple cycle combustion turbine have maintained this emissions rate. Both of these are common aeroderivative turbines and since they do require an intercooler have potential space consideration advantages compared to the LMS100. Finalizing the proposed emissions standard could restrict new intermediate load simple cycle turbine to the use of intercooling, limiting application to locations that can support a cooling tower. An intermediate load emissions rate of 1,170 lb CO_2/MWh-gross has been achieved by three-quarters of both the LMS100 and STG–A65 installations and 20 percent of LM6000 installations. In addition, this emissions rate has been demonstrated by a frame simple turbine. The EPA notes that the more efficient versions of the combustion turbines—water injection in the case of the LMS 100 and DLN in the case of the STG–A65—have higher design efficiencies and higher compliance levels than the version with the alternate NO_X control technology. This standard of performance has been demonstrated by 40 percent of recently installed intermediate load simple cycle turbines and the Agency has determined that with proper maintenance is achievable with combustion turbines from multiple manufacturers, with and without intercooling, and is finalizing a standard of 1,170 lb CO_2/MWh-gross for intermediate load combustion turbines. The EPA considered, but rejected, finalizing an emissions standard of 1,190 lb CO_2/MWh-gross. This standard of performance has been achieved by essentially all LMS 100 and SGT–A65 intermediate load simple cycle turbines and 70 percent of recently installed intermediate load simple cycle turbines but would not require the most efficient available versions of new intermediate load simple cycle turbines and does not represent the BSER.

2. Phase-2 Standards

The EPA proposed that 90 percent CCS (as part of the CCS pathway) qualifies as the second component of the BSER for base load combustion turbines. For the base load combustion turbines, the EPA reduced the emissions rate by 89 percent to determine the CCS based phase-2 standards.[879] The CCS percent reduction is based on a CCS system capturing 90 percent of the emitting CO_2 being operational anytime the combustion turbine is operating. Similar to the phase-1 emission standards, the EPA proposed and is finalizing a decision that standard of performance for base load combustion turbines be adjusted based on the uncontrolled emission rates of the fuels relative to natural gas. For 100 percent distillate oil-fired combustion turbines, the emission rates would be 120 lb CO_2/MWh-gross.

The EPA solicited comment on the range of reduction in emission rate of 75 to 90 percent. In addition, the EPA solicited comment on whether carbon capture equipment has lower availability/reliability than the combustion turbine or the CCS equipment takes longer to startup than the combustion turbine itself there would be periods of operation where the CO_2 emissions would not be controlled by the carbon capture equipment. For the same reasons as for coal-fired EGUs, the EPA has determined 90 percent CCS

the EPA assumed a linear relationship for combined cycle efficiency with turbine engines with base load ratings of less than 2,000 MMBtu/h.

[879] The 89 percent reduction from CCS accounts for the increased auxiliary load of a 90 percent post combustion amine-based capture system. Due to rounding, the proposed numeric standards of performance do not necessarily match the standards that would be determined by applying the percent reduction to the phase-1 standards.

has been demonstrated and appropriate for base load combustion turbines, see section VII.C.

H. Reconstructed Stationary Combustion Turbines

All the major manufacturers of combustion turbines sell upgrade packages that increase both the output and efficiency of existing combustion turbines. An owner/operator of a reconstructed combustion turbine would be able to use one of these upgrade packages to comply with the intermediate load emission standards in this final rule. Some examples of these upgrades include GE's Advanced Gas Path, Siemens' Hot Start on the Fly, and Solar Turbines' Gas Compressor Restaging. The Advanced Gas Path option includes retrofitting existing turbine components with improved materials to increase durability, air sealing, and overall efficiency.[880] Hot Start on the Fly upgrades include implementing new software to allow for the gas and steam turbine to start-up simultaneously, which greatly improves start times, and in some cases could do so by up to 20 minutes.[881] Compressor restaging involves analyzing the current operation of an existing combustion turbine and adjusting its gas compressor characteristics including transmission, injection, and gathering, to operate in the most efficient manner given the other operating conditions of the turbine.[882] In addition, steam injection is a retrofittable technology that is estimated to be available for a total cost of all the equipment needed for steam injection of $250/kW.[883] Due to the differences in materials used and necessary additional infrastructure, a steam injection system can be up to 60 percent smaller than a similar HRSG, which is valuable for retrofit purposes.[884]

For owners/operators of base load combustion turbines, however, HRSG have been added to multiple existing simple cycle turbines to convert to combined cycle technology. There have been multiple examples of this kind of conversion from simple cycle to combined cycle. One such example is Unit 12 at Riverton Power Plant in Riverton, Kansas, which was originally built in 2007 as a 143 MW simple cycle combustion turbine. In 2013, an HRSG and additional equipment was added to convert Unit 12 to a combined cycle combustion turbine.[885] Another is Energy Center Dover, located in Dover, Delaware, which in addition to a coal-fired steam turbine, originally had two 44 MW simple cycle combustion turbines. Also in 2013, the unit added an HRSG to one of the existing simple cycle combustion turbines, connected the existing steam generator to it, and retired the remaining coal-related equipment to convert that combustion turbine to a combined cycle one.[886] Some other examples include the Los Esteros Critical Energy Facility in San Jose, California, which converted from a four-turbine simple cycle peaking facility to a combined-cycle one in 2013, and the Tracy Combined Cycle Power Plant.[887] The Tracy facility, located in Tracy, California, was built in 2003 with two simple cycle combustion turbines and in 2012 was converted to combined cycle with the addition of a steam turbine.[888]

In the previous sections, the EPA explained the background of and requirements for new and reconstructed stationary combustion turbines and evaluated various control technology configurations to determine the BSER. Because the BSER is the same for new and reconstructed stationary combustion turbines, the Agency used the same emissions analysis for both new and reconstructed stationary combustion turbines. For each of the subcategories, the EPA proposed and is finalizing a conclusion that the BSER results in the same standard of performance for new stationary combustion turbines and reconstructed stationary combustion turbines. For CCS, consistent with the NETL Combined Cycle CCS Retrofit Report, the EPA approximated the cost to add CCS to a reconstructed combustion turbine by increasing the capital costs of the carbon capture equipment by 9 percent relative to the costs of adding CCS to a newly constructed combustion turbine and decreasing the net efficiency by 0.3 percent.[889] Using the same costing assumptions for newly constructed combined cycle turbines, the compliance costs for reconstructed combined cycle turbines are approximately 10 percent higher than for comparable newly constructed combined cycle turbine. Assuming continued operation of the capture equipment, the compliance costs are $17/MWh and $51/ton ($56/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $21/MWh and $63/ton ($69/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine. If the capture system is not operated while the combustion turbine is subcategorized as in intermediate load combustion turbine, the compliance costs are reduced to $10/MWh and $50/ton ($55/metric ton) for a 6,100 MMBtu/h H-Class combustion turbine, and $13/MWh and $67/ton ($73/metric ton) for a 4,600 MMBtu/h F-Class combustion turbine.

A reconstructed stationary combustion turbine is not required to meet the standards if doing so is deemed to be ''technologically and economically'' infeasible.[890] This provision requires a case-by-case reconstruction determination in the light of considerations of economic and technological feasibility. However, this case-by-case determination considers the identified BSER, as well as technologies the EPA considered, but rejected, as BSER for a nationwide rule. One or more of these technologies could be technically feasible and of reasonable cost, depending on site-specific considerations and if so, would likely result in sufficient GHG reductions to comply with the applicable reconstructed standards. Finally, in some cases, equipment upgrades, and best operating practices would result in sufficient reductions to achieve the reconstructed standards.

I. Modified Stationary Combustion Turbines

CAA section 111(a)(4) defines a ''modification'' as ''any physical change in, or change in the method of operation of, a stationary source'' that either ''increases the amount of any air pollutant emitted by such source or . . . results in the emission of any air pollutant not previously emitted.'' Certain types of physical or operational changes are exempt from consideration as a modification. Those are described in 40 CFR 60.2, 60.14(e).

In the 2015 NSPS, the EPA did not finalize standards of performance for stationary combustion turbines that conduct modifications; instead, the EPA concluded that it was prudent to delay

[880] *https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/advanced-gas-path-brochure.pdf.*

[881] *https://www.siemens-energy.com/global/en/home/stories/trianel-power-plant-upgrades.html.*

[882] *https://s7d2.scene7.com/is/content/Caterpillar/CM20191213-93d46-8e41d.*

[883] ''GTI'' (2019). Innovative Steam Technologies. *https://otsg.com/industries/powergen/gti/.*

[884] Ibid.

[885] *https://www.nsenergybusiness.com/news/newsempire-district-starts-riverton-plants-combined-cycle-expansion-231013/.*

[886] *https://news.delaware.gov/2013/07/26/repowered-nrg-energy-center-dover-unveiled-gov-markell-congressional-delegation-dnrec-sec-omara-other-officials-join-with-nrg-to-announce-cleaner-natural-gas-facility/.*

[887] *https://www.calpine.com/los-esteros-critical-energy-facility.*

[888] *https://www.middleriverpower.com/#portfolio.*

[889] ''Cost and Performance of Retrofitting NGCC Units for Caron Capture—Revision 3.'' DOE/NETL–2023/3845. March 17, 2023.

[890] 40 CFR 60.15(b)(2).

issuing standards until the Agency could gather more information (80 FR 64515; October 23, 2015). There were several reasons for this determination: few sources had undertaken NSPS modifications in the past, the EPA had little information concerning them, and available information indicated that few owners/operators of existing combustion turbines would undertake NSPS modifications in the future; and since the Agency eliminated proposed subcategories for small EGUs in the 2015 NSPS, questions were raised as to whether smaller existing combustion turbines that undertake a modification could meet the final performance standard of 1,000 lb CO_2/MWh-gross.

It continues to be the case that the EPA is aware of no evidence indicating that owners/operators of combustion turbines intend to undertake actions that could qualify as NSPS modifications in the future. The EPA did not propose or solicit comment on standards of performance for modifications of combustion turbines and is not establishing any in this final rule.

J. Startup, Shutdown, and Malfunction

In its 2008 decision in *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), the D.C. Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. Specifically, the court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that the SSM exemption violates the requirement under section 302(k) of the CAA that some CAA section 112 standard apply continuously. The EPA has determined the reasoning in the court's decision in *Sierra Club* v. *EPA* applies equally to CAA section 111 because the definition of emission or standard in CAA section 302(k), and the embedded requirement for continuous standards, also applies to the NSPS. Consistent with *Sierra Club* v. *EPA,* the EPA is finalizing standards in this rule that apply at all times. The NSPS general provisions in 40 CFR 60.11(c) currently exclude opacity requirements during periods of startup, shutdown, and malfunction and the provision in 40 CFR 60.8(c) contains an exemption from non-opacity standards. These general provision requirements would automatically apply to the standards set in an NSPS, unless the regulation specifically overrides these general provisions. The NSPS subpart TTTT (40 CFR part 60, subpart TTTT) does not contain an opacity standard, thus, the requirements at 40 CFR 60.11(c) are not applicable. The NSPS subpart TTTT also overrides 40 CFR 60.8(c) in table 3 and requires that sources comply with the standard(s) at all times. In reviewing NSPS subpart TTTT and proposing the new NSPS subpart TTTTa, the EPA proposed to retain in subpart TTTTa the requirements that sources comply with the standard(s) at all times in table 3 of the new subpart TTTTa to override the general provisions for SSM exemption related provisions. The EPA proposed and is finalizing that all standards in subpart TTTTa apply at all times.

In developing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained in this section of the preamble, is not establishing alternate standards for those periods. The EPA analysis of achievable standards of performance used CEMS data that includes all period of operation. Since periods of startup, shutdown, and malfunction were not excluded from the analysis, the EPA is not establishing alternate standard for those periods of operation.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment. (40 CFR 60.2). The EPA interprets CAA section 111 as not requiring emissions that occur during periods of malfunction to be factored into development of CAA section 111 standards. Nothing in CAA section 111 or in caselaw requires that the EPA consider malfunctions when determining what standards of performance reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. While the EPA accounts for variability in setting standards of performance, nothing in CAA section 111 requires the Agency to consider malfunctions as part of that analysis. The EPA is not required to treat a malfunction in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the EPA to consider such events in setting CAA section 111 standards of performance. The EPA's approach to malfunctions in the analogous circumstances (setting ''achievable'' standards under CAA section 112) has been upheld as reasonable by the D.C. Circuit in *U.S. Sugar Corp.* v. *EPA,* 830 F.3d 579, 606–610 (2016).

K. Testing and Monitoring Requirements

Because the NSPS reflects the application of the best system of emission reduction under conditions of proper operation and maintenance, in doing the NSPS review, the EPA also evaluates and determines the proper testing, monitoring, recordkeeping and reporting requirements needed to ensure compliance with the NSPS. This section includes a discussion on the current testing and monitoring requirements of the NSPS and any additions the EPA is including in 40 CFR part 60, subpart TTTTa.

1. General Requirements

The EPA proposed to allow three approaches for determining CO_2 emissions: a CO_2 CEMS and stack gas flow monitor; hourly heat input, fuel characteristics, and F factors [891] for EGUs firing oil or gas; or Tier 3 calculations using fuel use and carbon content. The first two approaches are in use for measuring CO_2 by units affected by the Acid Rain program (40 CFR part 75), to which most, if not all, of the EGUs affected by NSPS subpart TTTT are already subject, while the last approach is in use for stationary fuel combustion sources reporting to the GHGRP (40 CFR part 98, subpart C).

The EPA believes continuing the use of approaches already in use by other programs represents a cost-effective means of obtaining quality assured data requisite for determining carbon dioxide mass emissions. MPS reporting software required by this subpart for reporting emissions to the EPA expects hourly or daily CO_2 emission values and has thousands of electronic checks to validate data using the Acid Rain program requirements (40 CFR part 75). ECMPS does not currently accommodate or validate data under GHGRP's Tier 3 approach. Because most, if not all, of the EGUs that will be affected by this final rule are already affected by Acid Rain program monitoring requirements, the cost and burden for EGU owners or operators are already accounted for by other rulemakings. Therefore, this aspect of the final rule is designed to have minimal, if any, cost or burden associated with CO_2 testing and monitoring. In addition, there are no changes to measurement and testing requirements for determining electrical output, both gross and net, as well as

[891] An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel.

thermal output, to existing requirements.

However, the EPA requested comment on whether continuous CO_2 CEMS and stack gas flow measurements should be the sole means of compliance for this rule. Such a switch would increase costs for those EGU owners or operators who are currently relying on the oil- or gas-fired calculation-based approaches. By way of reference, the annualized cost associated with adoption and use of continuous CO_2 and flow measurements where none now exist is estimated to be about $52,000. To the extent that the rule were to mandate continuous CO_2 and stack gas flow measurements in accordance with what is currently allowed as one option and that an EGU lacked this instrumentation, its owner or operator would need to incur this annual cost to obtain such information and to keep the instrumentation calibrated. Commenters encouraged the EPA to maintain the flexibility for EGUs to use hourly heat input measurements, fuel characteristics, and F factors as is allowed under the Acid Rain program. Commenters argued that in addition to the incremental costs, some facilities have space constraints that could make the addition of stack gas flow monitors difficult or impractical. In this final rule, the EPA allows the use of hourly heat input, fuel characteristics, and F factors as an alternative to CO_2 CEMS and stack gas flow monitors for EGUs that burn oil or gas.

One commenter argued that the part 75 data requirements, which are required for several emission trading programs including the Acid Rain program, are punitive and that the data are biased high. Other commenters argued that the part 75 CO_2 data are biased low. EPA disagrees that the data requirements are punitive. Most, if not all, of the EGUs subject to this subpart are already reporting the data under the Acid Rain program. Oil- and gas-fired EGUs that are not subject to the Acid Rain program but are subject to a Cross-State Air Pollution Rule program are already reporting most of the necessary data elements (*e.g.,* hourly heat input and F factors) for SO_2 and/or NO_X emissions. The additional data and effort necessary to calculate CO_2 emissions is minor. The EPA also disagrees that the data are biased significantly high or low. Each CO_2 CEMS and stack gas flow monitor must undergo regular quality assurance and quality control activities including periodic relative accuracy test audits where the EGU's monitoring system is compared to an independent monitoring system. In a May 2022 study conducted by the EPA, the average difference between the EGU's monitoring system and the independent monitoring system was approximately 2 percent for CO_2 concentration and slightly greater than 2 percent for stack gas flow.

2. Requirements for Sources Implementing CCS

The CCS process is also subject to monitoring and reporting requirements under the EPA's GHGRP (40 CFR part 98). The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the U.S. The ''suppliers of carbon dioxide'' source category of the GHGRP (GHGRP subpart PP) requires those affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied. Facilities that inject a CO_2 stream underground for long-term containment in subsurface geologic formations report quantities of CO_2 sequestered under the ''geologic sequestration of carbon dioxide'' source category of the GHGRP (GHGRP subpart RR). In April 2024, to complement GHGRP subpart RR, the EPA finalized the ''geologic sequestration of carbon dioxide with enhanced oil recovery (EOR) using ISO 27916'' source category of the GHGRP (GHGRP subpart VV) to provide an alternative method of reporting geologic sequestration in association with EOR.[892] [893] [894]

CCS as the BSER, as detailed in section VIII.F.4.c.iv of this preamble, is determined to be adequately demonstrated based solely on geologic sequestration that is not associated with EOR. However, EGUs also have the compliance option to send CO_2 to EOR facilities that report under GHGRP subpart RR or GHGRP subpart VV. The EPA is requiring that any affected unit that employs CCS technology that captures enough CO_2 to meet the proposed standard and injects the captured CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility that reports in accordance with GHGRP subpart RR or GHGRP subpart VV. This does not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC program under the Safe Drinking Water Act.

The EPA also notes that compliance with the standard is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic sequestration site are not part of that calculation, though the EPA anticipates that the quantity of CO_2 sequestered will be substantially similar to the quantity captured. However, to verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, the Agency is leveraging regulatory reporting requirements under the GHGRP. The EPA also emphasizes that this final rule does not involve regulation of downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. The requirement that the emitting EGU transfer the captured CO_2 to an entity subject to the GHGRP requirements is thus exclusively an element of enforcement of the EGU standard. This avoids duplicative monitoring, reporting, and verification requirements between this rule and the GHGRP, while also ensuring that the facility injecting and sequestering the CO_2 (which may not necessarily be the EGU) maintains responsibility for these requirements. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of this final rule.

L. Recordkeeping and Reporting Requirements

The current rule (subpart TTTT of 40 CFR part 60) requires EGU owners or operators to prepare reports in accordance with the Acid Rain Program's ECMPS. Such reports are to be submitted quarterly. The EPA believes all EGU owners and operators have extensive experience in using the ECMPS and use of a familiar system ensures quick and effective rollout of the program in this final rule. Because all EGUs are expected to be covered by and included in the ECMPS, minimal, if any, costs for reporting are expected for

[892] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[893] International Standards Organization (ISO) standard designated as CSA Group (CSA)/American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (referred to as ''CSA/ANSI ISO 27916:2019'').

[894] As described in 87 FR 36920 (June 21, 2022), both subpart RR and subpart VV (CSA/ANSI ISO 27916:2019) require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. Primary differences relate to the terms in their respective mass balance equations, how each defines leakage, and when facilities may discontinue reporting.

this final rule. In the unlikely event that a specific EGU is not already covered by and included in the ECMPS, the estimated annual per unit cost would be about $8,500.

The current rule's recordkeeping requirements at 40 CFR part 60.5560 rely on a combination of general provision requirements (see 40 CFR 60.7(b) and (f)), requirements at subpart F of 40 CFR part 75, and an explicit list of items, including data and calculations; the EPA is retaining those existing subpart TTTT of 40 CFR part 60 requirements in the new NSPS subpart TTTTa of 40 CFR part 60. The annual cost of those recordkeeping requirements will be the same amount as is required for subpart TTTT of 40 CFR part 60 recordkeeping. As the recordkeeping in subpart TTTT of 40 CFR part 60 will be replaced by similar recordkeeping in subpart TTTTa of 40 CFR part 60, this annual cost for recordkeeping will be maintained.

M. Compliance Dates

Owners/operators of affected sources that commenced construction or reconstruction after May 23, 2023, must meet the requirements of 40 CFR part 60, subpart TTTTa, upon startup of the new or reconstructed affected facility or the effective date of the final rule, whichever is later. This compliance schedule is consistent with the requirements in section 111 of the CAA.

N. Compliance Date Extension

Several industry commenters noted the potential for delay in installation and utilization of emission controls—especially CCS—due to supply chain constraints, permitting challenges, environmental assessments, or delays in development of necessary infrastructure, among other reasons. Commenters requested that the EPA include a mechanism to extend the compliance date for affected EGUs that are installing emission controls. These commenters explained that an extension mechanism could provide greater regulatory certainty for owners and operators.

After considering these comments, the EPA believes that it is reasonable to provide a consistent and transparent means of allowing a limited extension of the Phase 2 compliance deadline where an affected new or reconstructed base load stationary combustion EGU has demonstrated such an extension is needed for installation and utilization of controls. This mechanism is intended to address unavoidable delays in implementation—not to provide more time to assess the NSPS compliance strategy for the affected EGU.

As indicated, the EPA is finalizing a provision that will allow the owner/operators of new or reconstructed base load stationary combustion turbine EGUs to request a limited Phase 2 compliance extension based on a case-by-case demonstration of necessity. Under these provisions, the owner or operator of an affected source may apply for a Phase 2 compliance date extension of up to 1 year to comply with the applicable emissions control requirements, which if approved by the EPA, would require compliance with Phase 2 standards of performance no later than January 1, 2033. This mechanism is only available for situations in which an affected source encounters a delay in installation or startup of a control technology that makes it impossible to commence compliance with Phase 2 standards of performance by January 1, 2032 (*i.e.,* the Phase 2 compliance date specified in section VIII.F.4 of this preamble).

The EPA will grant a request for a Phase 2 compliance extension of up to 1 year only where a source demonstrates that it has taken all steps possible to install and start up the necessary controls and still cannot comply with the Phase 2 standards of performance by the January 1, 2032 compliance date due to circumstances entirely beyond its control. Any request for a Phase 2 compliance extension must be received by the EPA at least 180 days before the January 1, 2032 Phase 2 compliance date. The owner/operator of the requesting source must provide documentation of the circumstances that precipitated the delay (or an anticipated delay) and demonstrate that those circumstances are entirely beyond the control of the owner/operator and that the owner/operator has no ability to remedy the delay. These circumstances may include, but are not limited to, delays related to permitting, delays in delivery or construction of parts necessary for installation or implementation of the control technology, or development of necessary infrastructure (*e.g.,* CO_2 pipelines).

The request must include documentation that demonstrates that the necessary controls cannot be installed or started up by the January 1, 2032 Phase 2 compliance date. This may include information and documentation obtained from a control technology vendor or engineering firm demonstrating that the necessary controls cannot be installed or started up by the applicable Phase 2 compliance date, documentation of any permit delays, or documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology. The owner/operator of an affected new stationary combustion turbine EGU remains subject to the January 1, 2032 Phase 2 compliance date unless and until the Administrator grants a compliance extension.

As discussed in sections VII.C.1.a.i.(E) and VII.C.2.b.i(C), the EPA has determined compliance timelines for these new sources that are consistent with achieving emission reductions as expeditiously as practicable given the time it takes to install and startup the BSER technologies for compliance with the Phase 2 standards of performance. The Phase 2 compliance dates are designed to accommodate the process steps and timeframes that the EPA reasonably anticipates will apply to affected EGUs. This extension mechanism acknowledges that circumstances entirely outside the control of the owners or operators of affected EGUs may extend the timeframe for installation or startup of control technologies beyond the timeframe that the EPA has determined is reasonable as a general matter. Thus, so long as this extension mechanism is limited to circumstances that cannot be reasonably controlled or remedied by the owners or operators of the affected EGUs and that make it impossible to achieve compliance with Phase 2 standards of performance by the January 1, 2032 compliance date, its use is consistent with achieving compliance as expeditiously as practicable.

The EPA believes that a 1-year extension on top of the lead time already provided by the 2032 compliance date should be sufficient to address any compliance delays and to allow all base load units to timely install CSS. New or reconstructed base load stationary combustion turbines that are granted a 1-year Phase 2 compliance date extension and still are not able to install or startup the control technologies necessary to meet the Phase 2 standard of performance by the extended Phase 2 compliance date of January 1, 2033 may adjust their operation to the intermediate load subcategory (*i.e.,* 12-operating-month capacity factor between 20–40 percent). Such sources must then comply with applicable standards of performance for the intermediate load stationary combustion turbine subcategory until the necessary controls are installed and operational such that the source can comply with the Phase 2 standard of performance.

IX. Requirements for New, Modified, and Reconstructed Fossil Fuel-Fired Steam Generating Units

A. 2018 NSPS Proposal Withdrawal

1. Background

As discussed in section V.B, the EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015 (''2015 NSPS'').[895] The 2015 NSPS finalized partial CCS as the BSER and finalized standards of performance to limit emissions of GHG manifested as CO_2 from newly constructed, modified, and reconstructed fossil fuel-fired EGUs (*i.e.,* utility boilers and integrated gasification combined cycle (IGCC) units). In the same document, the Agency also finalized CO_2 emission standards for newly constructed and reconstructed stationary combustion turbine EGUs. 80 FR 64510 (October 23, 2015). These final standards were codified in 40 CFR part 60, subpart TTTT.

On December 20, 2018, the EPA published a proposal to revise certain parts of the 2015 Rule, titled ''Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.'' 83 FR 65424 (December 20, 2018) (''2018 Proposal''). In Fall 2020, after reviewing comments on the 2018 Proposal, the EPA developed a draft final rule and sent that package to the Office of Management and Budget (OMB) for interagency review under Executive Order 12866 (''2020 OMB Review Package''). The 2020 OMB Review Package, if finalized, would have amended the BSER for new coal-fired EGUs and required a pollutant-specific significant contribution finding (SCF) prior to regulating a source category. The review of the BSER portion of the package was delayed [896] and the pollutant-specific SCF portion of the 2020 OMB Review Package was finalized on January 13, 2021 in a final rule, titled ''Pollutant-Specific Contribution Finding for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories.'' 86 FR 2542 (January 13, 2021) (''SCF Rule''). However, the D.C. Circuit vacated the SCF Rule on April 5, 2021.[897] The BSER analysis and that portion of the 2018 Proposal have not been finalized and are being withdrawn in this final action. The 2018 Proposal stated that the Agency was proposing to find that partial CCS is not the BSER on grounds that it is too costly and that the 2015 Rule did not show that the technology had sufficient geographic scope to qualify as the BSER for newly constructed coal-fired EGUs. The EPA instead proposed that the BSER for newly constructed coal-fired EGUs would be the most efficient available steam cycle (*i.e.,* supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with the best operating practices instead of partial CCS. In addition, for newly constructed coal-fired EGUs firing moisture-rich fuels (*i.e.,* lignite), the BSER would also include pre-combustion fuel drying using waste heat from the process. The 2018 Proposal also would have revised the standards of performance for reconstructed EGUs, the maximally stringent standards for coal-fired EGUs undergoing large modifications (*i.e.,* modifications resulting in an increase in hourly CO_2 emissions of more than 10 percent), and for base load and non-base load operating conditions that reflected the Agency's revised BSER determination. The 2018 Proposal did not revise the BSER for any other sources as determined in the 2015 Rule. It also included minor amendments to the applicability criteria for combined heat and power (CHP) and non-fossil EGUs and other miscellaneous technical changes in the regulatory requirements.

2. Withdrawal of the 2018 Proposal

In this action, under CAA section 111(b), the Agency is withdrawing the 2018 Proposal and the proposed determination that the BSER for coal-fired steam generating units should be highly efficient generation technology combined with best operating practices. The EPA no longer believes there is a basis for finding that highly efficient generation technology combined with best operating practices are the BSER for coal-fired steam generating units. As described at length in this preamble, CCS technology is adequately demonstrated for coal-fired steam generating units and so it is not appropriate to impose the less effective emission control of highly efficient generation combined with best operating practices for new sources in this source category. Moreover, the EPA is presently considering whether to revise the 2015 Rule to take into account improvements in CCS technology and the existing tax credits under the IRA. For a more in-depth, technical discussion of the rationale underlying this action, please refer to the technical memorandum in the docket titled, *2018 Proposal Withdrawal.*

B. Additional Amendments

The EPA proposed and is finalizing multiple less significant amendments. These amendments are either strictly editorial and will not change any of the requirements of 40 CFR part 60, subpart TTTT, or will add additional compliance flexibility. The amendments are also incorporated into the final subpart TTTTa. For additional information on these amendments, see the redline strikeout version of the rule showing the amendments in the docket for this action.

First, the EPA proposed and is finalizing editorial amendments to define acronyms the first time they are used in the regulatory text. Second, the EPA proposed and is finalizing adding International System of Units (SI) equivalent for owners/operators of stationary combustion turbines complying with a heat input-based standard. Third, the EPA proposed and is finalizing correcting errors in the current 40 CFR part 60, subpart TTTT, regulatory text referring to part 63 instead of part 60. Fourth, as a practical matter owners/operators of stationary combustion turbines subject to the heat input-based standard of performance need to maintain records of electric sales to demonstrate that they are not subject to the output-based standard of performance. Therefore, the EPA proposed and is finalizing adding a specific requirement that owner/operators maintain records of electric sales to demonstrate they did not sell electricity above the threshold that would trigger the output-based standard. Next, the EPA proposed and is finalizing updating the ANSI, ASME, and ASTM International (ASTM) test methods to include more recent versions of the test methods. Finally, the EPA proposed and is finalizing adding additional compliance flexibilities for EGUs either serving a common electric generator or using a common stack.

C. Eight-year Review of NSPS for Fossil Fuel-Fired Steam Generating Units

1. Modifications

In the 2015 NSPS, the EPA issued final standards for a steam generating

[895] 80 FR 64510 (October 23, 2015).

[896] As part of the interagency review process, an error in the partial CCS costing report that the EPA used to update the costs of partial CCS between the 2018 Proposal and 2020 OMB Review Package was identified. The error included in the original 2020 OMB Review Package had the impact of increasing the cost of partial CCS. The corrected report resulted in partial CCS costs that were similar to those included in the 2018 Proposal.

[897] *State of California* v. *EPA* (D.C. Cir. 21–1035), Document No. 1893155 (April 5, 2021).

unit that implements a ''large modification,'' defined as a physical change, or change in the method of operation, that results in an increase in hourly CO_2 emissions of more than 10 percent when compared to the source's highest hourly emissions in the previous 5 years. Such a modified steam generating unit is required to meet a unit-specific CO_2 emission limit determined by that unit's best demonstrated historical performance (in the years from 2002 to the time of the modification). The 2015 NSPS did not include standards for a steam generating unit that implements a ''small modification,'' defined as a change that results in an increase in hourly CO_2 emissions of less than or equal to 10 percent when compared to the source's highest hourly emissions in the previous 5 years.[898]

In the 2015 NSPS, the EPA explained its basis for promulgating this rule as follows. The EPA has historically been notified of only a limited number of NSPS modifications involving fossil fuel-fired steam generating units and therefore predicted that very few of these units would trigger the modification provisions and be subject to the proposed standards. Given the limited information that we have about past modifications, the Agency has concluded that it lacks sufficient information to establish standards of performance for all types of modifications at steam generating units at this time. Instead, the EPA has determined that it is appropriate to establish standards of performance at this time for larger modifications, such as major facility upgrades involving, for example, the refurbishing or replacement of steam turbines and other equipment upgrades that result in substantial increases in a unit's hourly CO_2 emissions rate. The Agency has determined, based on its review of public comments and other publicly available information, that it has adequate information regarding the types of modifications that could result in large increases in hourly CO_2 emissions, as well as on the types of measures available to control emissions from sources that undergo such modifications, and on the costs and effectiveness of such control measures, upon which to establish standards of performance for modifications with large emissions increases at this time.[899] The EPA did not reopen any aspect of these determinations concerning modifications in the 2015 NSPS, except, as noted below, for the BSER and associated requirements for large modifications.

Because the EPA has not promulgated a NSPS for small modifications, any existing steam generating unit that undertakes a change that increases its hourly CO_2 emissions rate by 10 percent or less will continue to be treated as an existing source that is subject to the CAA section 111(d) requirements being finalized today.

With respect to large modifications, the EPA explained in the 2015 NSPS that they are rare, but there is record evidence indicating that they may occur.[900] Because the EPA is finalizing requirements for existing coal-fired steam generating units that are, on their face, more stringent than the requirements for large modifications, the EPA believes it is appropriate to review and revise the latter requirements to minimize the anomalous incentive that an existing source could have to undertake a large modification for the purpose of avoiding the more stringent requirements that it would be subject to if it remained an existing source. Accordingly, the EPA proposed and is finalizing amending the BSER for large modifications for coal-fired steam generating units to mirror the BSER for the subcategory of long-term coal-fired steam generating units that is, the use of CCS with 90 percent capture of CO_2. The EPA believes that it is reasonable to assume that any existing source that invests in a physical change or change in the method of operation that would qualify as a large modification expects to continue to operate past 2039. Accordingly, the EPA has determined that CCS with 90 percent capture qualifies as the BSER for such a source for the same reasons that it qualifies as the BSER for existing sources that plan to operate past December 31, 2039. The EPA discusses these reasons in section VII.C.1.a of this preamble. The EPA has determined that CCS with 90 percent capture qualifies as the BSER for large modifications, and not the controls determined to be the BSER in the 2015 NSPS, due to the recent reductions in the cost of CCS.

By the same token, the EPA is finalizing that the degree of emission limitation associated with CCS with 90 percent capture is an 88.4 percent reduction in emission rate (lb CO_2/MWh-gross basis), the same as finalized for existing sources with CCS with 90 percent capture. See section VII.C.3.a of this preamble. Based on this degree of emission limitation, the EPA proposed and is finalizing that the standard of performance for steam generating units that undertake large modifications after May 23, 2023, is a unit-specific emission limit determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification). The EPA proposed and is finalizing that an owner/operator of a modified steam generating unit comply with the emissions rate upon startup of the modified affected facility or the effective date of the final rule, whichever is later. The EPA proposed and is finalizing the same testing, monitoring, and reporting requirements as are currently in 40 CFR part 60, subpart TTTT.

The EPA did not propose, and is not finalizing, any review or revision of the 2015 standard for large modifications of oil- or gas-fired steam generating units because the we are not aware of any existing oil- or gas-fired steam generating EGUs that have undertaken such modifications or have plans to do so, and, unlike an existing coal-fired steam generating EGUs, existing oil- or gas-fired steam units have no incentive to undertake such a modification to avoid the requirements we are including in this final rule for existing oil- or gas-fired steam generating units.

2. New Construction and Reconstruction

The EPA promulgated NSPS for GHG emissions from fossil fuel-fired steam generating units in 2015. In the proposal, the EPA proposed that it did not need to review the 2015 NSPS because at that time, the EPA did not have information indicating that any such units will be constructed or reconstructed. However, the EPA has recently become aware that a new coal-fired power plant is under consideration in Alaska. In November 2023, DOE announced a $9 million cooperative agreement for the Alaska Railbelt Carbon Capture and Storage (ARCCS) project, to be led by researchers at the University of Alaska Fairbanks. The ARCCS project would study the viability of a carbon storage complex in Southcentral Alaska, likely at the mostly-depleted Beluga River gas field west of Anchorage'' in the Cook Inlet Basin, which could store captured CO_2. According to reports, the privately owned Flatlands Energy Corp. is considering constructing a 400 MW coal- and biomass-fired power plant in the Susitna River valley region, which, if built, would be one of the sources of captured CO_2.[901]

[898] 80 FR 64514 (October 23, 2015).

[899] *Id.* at 64597–98.

[900] *Id.* at 64598.

[901] DOE Funding Opportunity Announcement, ''DOE Invests More Than $444 Million for CarbonSAFE Project,'' (November 15, 2023), *https://netl.doe.gov/node/13090*; University of Alaska

In light of this development, the EPA is not finalizing its proposal not to review the 2015 NSPS. Instead, the EPA will continue to consider whether to review the 2015 NSPS and will monitor the development of this potential new construction project in Alaska as well as any other potential projects to newly construct or reconstruct a coal-fired power plant. If the EPA does decide to review the 2015 NSPS, it would propose to revise them for coal-fired steam generating units.

D. Projects Under Development

During the 2015 NSPS rulemaking, the EPA identified the Plant Washington project in Georgia and the Holcomb 2 project in Kansas as EGU ''projects under development'' based on representations by developers that the projects had commenced construction prior to the proposal of the 2015 NSPS and, thus, would not be new sources subject to the final NSPS (80 FR 64542–43; October 23, 2015). The EPA did not set a performance standard at the time but committed to doing so if new information about the projects became available. These projects were never constructed and are no longer expected to be constructed.

The Plant Washington project was to be an 850 MW supercritical coal-fired EGU. The Environmental Protection Division (EPD) of the Georgia Department of Natural Resources issued air and water permits for the project in 2010 and issued amended permits in 2014.[902] [903] [904] In 2016, developers filed a request with the EPD to extend the construction commencement deadline specified in the amended permit, but the director of the EPD denied the request, effectively canceling the approval of the construction permit and revoking the plant's amended air quality permit.[905]

The Holcomb 2 project was intended to be a single 895 MW coal-fired EGU and received permits in 2009 (after earlier proposals sought approval for development of more than one unit). In 2020, after developers announced they would no longer pursue the Holcomb 2 expansion project, the air permits were allowed to expire, effectively canceling the project.

For these reasons, the EPA proposed and is finalizing a decision to remove these projects under the applicability exclusions in subpart TTTT.

X. State Plans for Emission Guidelines for Existing Fossil Fuel-Fired EGUs

A. Overview

This section provides information related to state plan development, including methodologies for establishing presumptively approvable standards of performance for affected EGUs, flexibilities for complying with standards of performance, and components that must be included in state plans as well as the process for submission. This section also addresses significant comments on and any changes to the proposed emission guidelines regarding state plans that the EPA is finalizing in this action.

State plan submissions under these emission guidelines are governed by the requirements of 40 CFR part 60, subpart Ba (subpart Ba).[906] The EPA finalized revisions to certain aspects of 40 CFR part 60, subpart Ba, in November 2023, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d)* (final subpart Ba).[907] Unless expressly amended or superseded in these emission guidelines, the provisions of subpart Ba apply. This section explicitly addresses any instances where the EPA is adding to, superseding, or otherwise varying the requirements of subpart Ba for the purposes of these particular emission guidelines.

As noted in the preamble of the proposed action, under the Tribal Authority Rule (TAR) adopted by the EPA, Tribes may seek authority to implement a plan under CAA section 111(d) in a manner similar to that of a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to that of a state for purposes of developing a Tribal Implementation Plan (TIP) implementing the emission guidelines. If a Tribe obtains approval and submits a TIP, the EPA will generally use similar criteria and follow similar procedures as those described for state plans when evaluating the TIP submission and will approve the TIP if appropriate. The EPA is committed to working with eligible Tribes to help them seek authorization and develop plans if they choose. Tribes that choose to develop plans will generally have the same flexibilities available to states in this process.

In section X.B of this document, the EPA describes the foundational requirement that state plans achieve an equivalent level of emission reduction to the degree of emission limitation achievable through application of the BSER as determined by the EPA. Section X.C describes the presumptive methodology for calculating the standards of performance for affected EGUs based on subcategory assignment, as well as requirements related to invoking RULOF to apply a less stringent standard of performance than results from the EPA's presumptive methodology. Section X.C also describes requirements for increments of progress for affected EGUs in certain subcategories and for establishing milestones and reporting obligations for affected EGUs that plan to permanently cease operations, as well as testing and monitoring requirements. In section X.D, the EPA describes how states are permitted to include flexibilities such as emission trading and averaging as compliance measures for affected EGUs in their state plans. Finally, section X.E describes what must be included in state plans, including plan components specific to these emission guidelines and requirements for conducting meaningful engagement, as well as the timing of state plan submission and EPA review of state plans and plan revisions.

In this section of the preamble, the term ''affected EGU'' means any existing fossil fuel-fired steam generating unit that meets the applicability criteria described in section VII.B of this preamble. Affected EGUs are covered by the emission guidelines being finalized in this action under 40 CFR part 60 subpart UUUUb.

Fairbanks, Institute of Northern Engineering, ''Cook Inlet Region Low Carbon Power Generation With Carbon Capture, Transport, and Storage Feasibility Study,'' *https://ine.uaf.edu/media/391133/cook-inlet-low-carbon-power-feasibility-study-uaf-pcorfinal.pdf*; Herz, Nathaniel, ''Could a new Alaska coal power plant be climate friendly? An $11 million study aims to find out,'' Northern Journal (December 29, 2923), republished in Anchorage Daily News, *https://www.adn.com/business-economy/energy/2023/12/29/could-a-new-alaska-coal-power-plant-be-climate-friendly-an-11-million-study-aims-to-find-out/*.

[902] *https://www.gpb.org/news/2010/07/26/judge-rejects-coal-plant-permits*.

[903] *https://www.southernenvironment.org/press-release/court-rules-ga-failed-to-set-safe-limits-on-pollutants-from-coal-plant/*.

[904] *https://permitsearch.gaepd.org/permit.aspx?id=PDF-OP-22139*.

[905] *https://www.southernenvironment.org/wp-content/uploads/legacy/words_docs/EPD_Plant_Washington_Denial_Letter.pdf*.

[906] 40 CFR 60.20a–60.29a.

[907] 88 FR 80480 (November 17, 2023). At the time of promulgation of these emission guidelines, the November 2023 updates to the CAA section 111(d) implementing regulations are subject to litigation in the D.C. Circuit Court of Appeals. *West Virginia* v. *EPA,* D.C. Circuit No. 24–1009. The outcome of that litigation will not affect any of the distinct requirements being finalized in these emission guidelines, which are not directly dependent on those procedural requirements. Moreover, regardless of the outcome of that litigation, the necessary regulatory framework will exist for states to develop and submit state plans that include standards of performance for affected EGUs pursuant to these emission guidelines and prior implementing regulations.

B. Requirement for State Plans To Maintain Stringency of the EPA's BSER Determination

As explained in section V.C of this preamble, CAA section 111(d)(1) requires the EPA to establish requirements for state plans that, in turn, must include standards of performance for existing sources. Under CAA section 111(a)(1), a standard of performance is ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the Administrator determines has been adequately demonstrated.'' That is, the EPA has the responsibility to determine the BSER for a given category or subcategory of sources and to determine the degree of emission limitation achievable through application of the BSER to affected sources.[908] The level of emission reductions required of existing sources under CAA section 111 is reflected in the EPA's presumptive standards of performance,[909] which achieve emission reductions under these emission guidelines through requiring cleaner performance by affected sources.

States use the EPA's presumptive standards of performance to establish requirements for affected sources in their state plans. In general, the standards of performance that states establish for affected sources must be no less stringent than the presumptive standards of performance in the applicable emission guidelines.[910] Thus, in order for the EPA to find a state plan ''satisfactory,'' that plan must address each affected EGU within the state and must achieve at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance, after accounting for any application of RULOF.[911] That is, while states have the discretion to establish the applicable standards of performance for affected EGUs in their state plans, the structure and purpose of CAA section 111 and the EPA's regulations require that those plans achieve an equivalent level of emission reductions as applying the EPA's presumptive standards of performance to each of those sources (again, after accounting for any application of RULOF). Section X.C of this preamble addresses how states maintain the level of emission reduction when establishing standards of performance, and section X.D of this preamble addresses how states maintain the level of emission reduction when incorporating compliance flexibilities.

Additionally, consistent with the understanding that the purpose of CAA section 111 is for affected sources to reduce their emissions through cleaner operation, the Agency is also clarifying that emissions reductions from sources *not* affected by the final emission guidelines may not be counted towards compliance with either a source-specific or aggregate standard of performance. In other words, state plans may not account for emission reductions at non-affected fossil fuel-fired EGUs, emission reductions due to the operation or installation of other electricity-generating resources not subject to these emission guidelines for the purposes of demonstrating compliance with affected EGUs' standards of performance.

C. Establishing Standards of Performance

This section addresses several topics related to standards of performance in state plans. First, this section describes affected EGUs' eligibility for the subcategories in the final emission guidelines and how to calculate presumptive standards of performance, including calculating unit-specific baseline emission performance. Second, it summarizes compliance date information as well as how states can provide for a compliance date extension mechanism in their state plans. Third, this section describes how states may consider RULOF to apply a less stringent standard of performance or a longer compliance schedule to a particular affected EGU. Fourth, it explains how states must establish certain increments of progress for affected EGUs installing control technology to comply with standards of performance, as well as milestones and reporting obligations for affected EGUs demonstrating that they plan to permanently cease operations. And, finally, this section describes emission testing and monitoring requirements.

Affected EGUs that meet the applicability requirements discussed in section VII.B must be addressed in the state plan. For each affected EGU within the state, the state plan must include a standard of performance and compliance schedule. That is, each individual unit must have its own, source-specific standard of performance and compliance schedule. Coal-fired affected EGUs must have increments of progress in the state plan and, if they plan to permanently cease operation and to rely on such cessation of operation for purposes of these emission guidelines, an enforceable commitment and reporting obligations and milestones. State plans must also specify the test methods and procedure for determining compliance with the standards of performance.

While a presumptive methodology for standards of performance and other requirements were proposed for existing combustion turbine EGUs, the EPA is not finalizing emission guidelines for such EGUs at this time; therefore, the following discussion will not address the proposed combustion turbine EGU requirements or comments pertaining to these proposed requirements. In addition, the EPA is not finalizing the imminent- and near-term coal-fired subcategories for coal-fired steam generating units; therefore, the following discussion will not address these proposed subcategories or comments pertaining to these proposed subcategories. Similarly, the EPA is not finalizing emission guidelines for states and territories in non-contiguous areas, and is therefore not finalizing the proposed subcategories for non-continental oil-fired steam generating units or associated requirements nor addressing comments pertaining to these subcategories in this section.

1. Application of Presumptive Standards

This section of the preamble describes the EPA's approach to providing presumptive standards of performance for each of the subcategories of affected EGUs under these emission guidelines, including establishing baseline emission performance. As explained in section X.B of this preamble, CAA section 111(a)(1) requires that standards of performance reflect the degree of emission limitation achievable through application of the BSER, as determined by the EPA. For each subcategory of affected EGUs, the EPA has determined a BSER and degree of emission limitation and is providing, in these emission guidelines, a methodology for

[908] *See, e.g., West Virginia* v. *EPA,* 597 U.S. 697, 720 (2022) (''In devising emissions limits for power plants, EPA first 'determines' the 'best system of emission reduction' that—taking into account cost, health, and other factors—it finds 'has been adequately demonstrated.' The Agency then quantifies 'the degree of emission limitation achievable' if that best system were applied to the covered source.'') (internal citations omitted).

[909] See 40 CFR 60.22a(b)(5).

[910] 40 CFR 60.24a(c).

[911] As explained in section X.C.2 of this preamble, states may invoke RULOF to apply a less stringent standard of performance to a particular affected EGU when the state demonstrates that the EGU cannot reasonably achieve the degree of emission limitation determined by the EPA. In this case, the state plan may not necessarily achieve the same stringency as each source achieving the EPA's presumptive standards of performance because affected EGUs for which RULOF has been invoked would have standards of performance less stringent than the EPA's presumptive standards.

establishing presumptively approvable standards of performance (also referred to as ''presumptive standards of performance'' or ''presumptive standards''). Appropriate use of these methodologies will result in standards of performance that achieve the requisite degree of emission limitation and therefore meet the statutory requirements of section 111(a)(1) and the corresponding regulatory requirement that standards of performance must generally be no less stringent that the corresponding emission guidelines.[912] 40 CFR 60.24a(c).

Thus, a state, when establishing standards of performance for affected EGUs in its plan, must identify each affected EGU in the state and specify into which subcategory each affected EGU falls. The state would then use the corresponding methodology for the given subcategory to establish the presumptively approvable standard of performance for each affected EGU.

As discussed in section X.C.2 of this preamble, states may apply less stringent standards of performance to particular affected EGUs in certain circumstances based on consideration of RULOF. States also have the authority to deviate from the methodology provided in these emission guidelines for presumptively approvable standards in order to apply a more stringent standard of performance (*e.g.,* a state decides that an affected EGU in the medium-term coal-fired subcategory should comply with a standard of performance corresponding to co-firing 50 percent natural gas instead of 40 percent). Application of a standard of performance that is more stringent than provided by the EPA's presumptive methodology does not require application of the RULOF provisions.[913]

a. Establishing Baseline Emission Performance for Presumptive Standards

For each subcategory, the methodology to calculate a standard of performance entails establishing a baseline of CO_2 emissions and corresponding electricity generation or heat input for an affected EGU and then applying the degree of emission limitation achievable through the application of the BSER (as established in section VII.C of this preamble). The methodology for establishing baseline emission performance for an affected EGU will result in a value that is unique to each affected EGU. To establish baseline emission performance for an affected EGU in all the subcategories except the low load natural gas- and oil-fired subcategories, the EPA is finalizing a determination that a state will use the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**. For affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, the EPA is finalizing a determination that a state will use the CO_2 mass emissions and corresponding heat input for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**. This period is based on the NSR program's definition of ''baseline actual emissions'' for existing electric steam generating units. See 40 CFR 52.21(b)(48)(i). Eight quarters of 40 CFR part 75 data corresponds to a 2-year period, but the EPA is finalizing this continuous 8-quarter period as it corresponds to quarterly reporting according to 40 CFR part 75. Functionally, the EPA expects states to utilize the most representative continuous 8-quarter period of data from the 5-year period immediately preceding the date the final rule is published in the **Federal Register**. For the 8 quarters of data, a state would divide the total CO_2 emissions (in the form of pounds) over that continuous time period by either the total gross electricity generation (in the form of MWh) or, for affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, the total heat input (in the form of MMBtu) over that same time period to calculate baseline CO_2 emission performance in either lb of CO_2 per MWh or lb of CO_2 per MMBtu. As an example, a state establishing baseline emission performance for an affected EGU in the medium-term coal-fired subcategory in the year 2023 would start by evaluating the CO_2 emissions and electricity generation data for the affected EGU for 2018 through 2022 and choose a continuous 8-quarter period that it deems to be the most appropriate representation of the operation of that affected EGU. While the EPA will evaluate the choice of baseline periods chosen by states when reviewing state plan submissions, the EPA intends to defer to a state's reasonable exercise of discretion as to which 8-quarter period is representative.

The EPA is finalizing the use of 8 quarters during the 5-year period prior to the date the final rule is published in the **Federal Register** as the relevant period for the baseline methodology for several reasons. First, each affected EGU has unique operational characteristics that affect the emission performance of the EGU (load, geographic location, hours of operation, coal rank, unit size, *etc.*), and the EPA believes each affected EGU's emission performance baseline should be representative of the source-specific conditions of the affected EGU and how it has typically operated. Additionally, allowing a state to choose (likely in consultation with the owners or operators of affected EGUs) the 8-quarter period for assessing baseline performance can avoid situations in which a prolonged period of atypical operating conditions would otherwise skew the emissions baseline. Relatedly, the EPA believes that, by using total mass CO_2 emissions and total electric generation or heat input for an affected EGU over an 8-quarter period, any relatively short-term variability of data due to seasonal operations or periods of startup and shutdown, or other anomalous conditions, will be averaged into the calculated level of baseline emission performance. The baseline-setting approach also aligns with the reporting and compliance requirements in the final emission guidelines. Using total mass CO_2 emissions and total electric generation or heat input provides a simple and streamlined approach for calculating baseline emission performance without the need to sort and filter non-representative data; any minor amount of non-representative data will be subsumed and accounted for through implicit averaging over the course of the 8-quarter period. Moreover, by not sorting or filtering the data, this approach reduces the need for discretion in assessing whether the data is appropriate to use. Commenters generally supported the proposed methodology for setting a baseline, particularly saying that they prefer not to have to sort or filter any data.

The EPA believes that using this baseline-setting approach as the basis for establishing presumptively approvable standards of performance will provide certainty for states, as well as transparency and a streamlined process for state plan development. While this approach is specifically designed to be flexible enough to

[912] Should a state decide to establish a standard of performance for an affected EGU using a methodology other than that provided by the EPA in these emission guidelines, the state would have to demonstrate that the resulting standard of performance achieves equivalent emission reductions as application of the EPA's presumptive standard of performance.

[913] 88 FR 80529–31 (November 17, 2023).

accommodate unit-specific circumstances, states retain the ability to deviate from this methodology. The EPA believes that the instances in which a state may need to use an alternate baseline-setting methodology will be limited to anticipated changes in operation, (*i.e.,* circumstances in which historical emission performance is not representative of future emission performance). States that wish to vary the baseline calculation for an affected EGU based on anticipated changes in operation of that EGU, when those changes result in a less stringent standard of performance, must use the RULOF mechanism, which is designed to address such contingencies.

Comment: Commenters sought clarification as to whether the methodology referred to the previous 5 calendar years or the 5-year period ending on the most recent quarter reported under 40 CFR part 75 prior to publication of the final emission guidelines.

Response: The EPA clarifies that the methodology refers to the 5-year period ending on the most recent quarter reported under 40 CFR part 75 prior to publication of the final emission guidelines in the **Federal Register**.

b. Presumptive Standards for Fossil Fuel-Fired Steam Generating Units

As described in section VII of this preamble, the EPA is finalizing separate subcategories of existing fossil fuel-fired steam generating units based on fuel type (*i.e.,* coal-fired, natural gas-fired, or oil-fired). Fuel type is based on the status of the source on January 1, 2030, and annual fuel use reporting is required after that date as a part of compliance. The EPA is further creating a subcategory for coal-fired steam generating units operating in the medium term, and further subcategorizing natural gas- and oil-fired steam generating units by load level.

Consistent with CAA section 111(d)(1)'s requirement that state plans provide for the implementation and enforcement of standards of performance, for affected EGUs in the medium-term subcategory, states must include sources' enforceable commitments to cease operating before January 1, 2039, in their plans. The state plan must specify the calendar date by which the affected EGU plans to cease operation; to be included in a state plan, a commitment to cease operations by such a date must be enforceable by the state, whether through state rule, agreed order, permit, or other legal instrument.[914] Upon EPA approval of the state plan, that commitment will become federally- and citizen-enforceable.

For affected oil- and natural gas-fired steam generating units, subcategories are defined by load level and the type of fuel fired. There are three subcategories for natural gas- and oil-fired steam generating units (base load, intermediate load, and low load). Because subcategory applicability is determined retrospectively, as opposed to prospectively, and because the standards of performance for oil- and natural gas-fired affected EGUs are based on BSERs that do not require add-on controls, it is not necessary to require these sources to take enforceable utilization commitments limiting them to just one subcategory in order to implement and enforce their standards. For steam generating units that meet the definition of natural gas- or oil-fired, and that either retain the capability to fire coal after the date this final rule is published in the **Federal Register**, that fired any coal during the 5-year period prior to that date, or that will fire any coal after that date and before January 1, 2030, the plan must include a requirement to remove the capability to fire coal before January 1, 2030.

The EPA is finalizing a requirement that compliance be demonstrated annually. For affected EGUs in all subcategories except the low load natural gas- and oil-fired subcategory, an affected EGU must demonstrate compliance based on the lb CO_2/MWh emission rate derived by dividing the total reported CO_2 mass emissions by the total reported electric generation during the compliance period (corresponding to 1 calendar year), which is consistent with the expression of the degree of emission limitation for each subcategory in sections VII.C.3 and VII.D.3. For affected EGUs in the low load natural gas- and oil-fired subcategory, an affected EGU must demonstrate compliance based on the lb CO_2/MMBtu emission rate derived by dividing the total reported CO_2 mass emissions by the total reported heat input during the compliance period (again, corresponding to 1 calendar year), consistent with the expression of the degree of emission limitation for the subcategory in section VII.D.3.[915] In other words, for units with a compliance date of January 1, 2030, the first compliance period will be January 1, 2030, through December 31, 2030. For units with a compliance date of January 1, 2032, the first compliance period will be January 1, 2032, through December 31, 2032. The compliance demonstration must occur by March 1 of the following year (*i.e.,* for the 2030 compliance period, by March 1, 2031).

In addition, the EPA is finalizing a requirement that standards of performance must be established as either a rate or, for affected EGUs in certain subcategories, a mass of emissions. If a state chooses to allow mass-based compliance for certain affected EGUs it must first calculate the rate-based emission limitation that corresponds to the presumptive standard of performance, and then explain how it translated that rate-based emission limitation into the mass that constitutes an affected EGU's standard of performance. See section X.D of this preamble for more information on demonstrating compliance where states are incorporating compliance flexibilities.

i. Long-Term Coal-Fired Steam Generating Units

This section describes the EPA's methodology for establishing presumptively approvable standards of performance for long-term coal-fired steam generating units. Affected coal-fired steam generating units that do not meet the specifications of the medium-term coal-fired EGU subcategory are necessarily long-term units, and have a BSER of CCS with 90 percent capture and a degree of emission limitation of 90 percent capture of the mass of CO_2 in the flue gas (*i.e.,* the mass of CO_2 after the boiler but before the capture equipment) over an extended period of time and an 88.4 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*i.e.,* an annual calendar-year basis). The EPA is finalizing a determination that where states use the methodology described here to establish standards of performance for affected EGUs in this subcategory, those established standards will be presumptively approvable when included in a state plan submission.

Establishing a standard of performance for an affected coal-fired EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described in section X.C.1.a of this preamble); and applying the degree of emission limitation, based on the application of the BSER, to that level of baseline emission performance. Implementation of CCS with a capture rate of 90 precent translates to a degree

[914] 40 CFR 60.26a.

[915] If the state plan incorporates compliance flexibilities like emission averaging and trading, an affected EGU must demonstrate compliance consistent with the expression of the respective flexibility. See section X.D of this preamble for more information.

of emission limitation comprising of an 88.4 percent reduction in CO_2 emission rate compared to the baseline level of emission performance. Using the complement of 88.4 percent (*i.e.,* 11.6 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance. For example, if a long-term coal-fired EGU's level of baseline emission performance is 2,000 lbs CO_2 per MWh, it will have a presumptively approvable standard of performance of 232 lbs CO_2 per MWh (2,000 lbs CO_2 per MWh multiplied by 0.116).

The EPA is also finalizing a requirement that affected coal-fired EGUs in the long-term subcategory comply with federally enforceable increments of progress, which are described in section X.C.3 of this preamble.

ii. Medium-Term Coal-Fired Steam Generating Units

This section describes the EPA's methodology for establishing presumptively approvable standards of performance for medium-term coal-fired steam generating units. Affected coal-fired steam generating units that plan to commit to permanently cease operations before January 1, 2039, have a BSER of 40 percent natural gas co-firing on a heat input basis. The EPA is finalizing a determination that where states use the methodology described here to establish standards of performance for an affected EGU in this subcategory, those established standards of performance would be presumptively approvable when included in a state plan submission.

Establishing a standard of performance for an affected EGU in this subcategory consists of two steps: establishing a source-specific level of baseline emission performance (as described in section X.C.1.a); and applying the degree of emission limitation, based on the application of the BSER, to that level of baseline emission performance. Implementation of natural gas co-firing at a level of 40 percent of total annual heat input translates to a level of stringency of a 16 percent reduction in emission rate on a lb CO_2/MWh-gross basis over an extended period of time (*i.e.,* an annual calendar-year basis) compared to the baseline level of emission performance. Using the complement of 16 percent (*i.e.,* 84 percent) and multiplying it by the baseline level of emission performance results in the presumptively approvable standard of performance for the affected EGU. For example, if a medium-term coal-fired EGU's level of baseline emission performance is 2,000 lbs CO_2 per MWh, it will have a presumptively approvable standard of performance of 1,680 CO_2 lbs per MWh (2,000 lbs CO_2 per MWh multiplied by 0.84).

For medium-term coal-fired steam generating units that have an amount of co-firing that is reflected in the baseline operation, the EPA is finalizing a requirement that states account for such preexisting co-firing in adjusting the degree of emission limitation. If, for example, an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to a 12 percent reduction in CO_2 emission rate on a lb CO_2/MWh-gross basis compared to the baseline level of emission performance (*i.e.,* an additional 30 percent of natural gas by heat input) to reflect the preexisting level of natural gas co-firing. This results in a standard of performance based on the degree of emission limitation achieving an additional 30 percent co-firing beyond the 10 percent that is accounted for in the baseline. The EPA believes this approach is a more straightforward mathematical adjustment than adjusting the baseline to appropriately reflect a preexisting level of co-firing.

The standard of performance for the medium-term coal-fired subcategory is based on the degree of emission limitation that is achievable through application of the BSER to the affected EGUs in the subcategory and consists exclusively of the rate-based emission limitation. However, the BSER determination for this subcategory is predicated on the assumption that affected EGUs within it will permanently cease operations prior to January 1, 2039. If a state decides to place an affected EGU in the medium-term coal-fired subcategory, the state plan must include that EGU's commitment to permanently cease operating as an enforceable requirement. The state plan must also include provisions that provide for the implementation and enforcement of this commitment, including requirements for monitoring, reporting, and recordkeeping.

Affected coal-fired EGUs that are relying on commitments to cease operating must comply with the milestones and reporting requirements as specified under these emission guidelines. The EPA intends these milestones to assist affected EGUs in ensuring they are completing the necessary steps to comply with their state plan requirements and to help ensure that any issues with implementation are identified in a timely and efficient manner. These milestones are described in detail in section X.C.4 of this preamble. Affected EGUs in this subcategory would also be required to comply with the federally enforceable increments of progress described in section X.C.3 of this preamble.

iii. Natural Gas-Fired Steam Generating Units and Oil-Fired Steam Generating Units

This section describes the EPA's final methodology for presumptively approvable standards of performance for the following subcategories of affected natural gas-fired and oil-fired steam generating units: low load natural gas-fired steam generating units, intermediate load natural gas-fired steam generating units, base load natural gas-fired steam generating units, low load oil-fired steam generating units, intermediate load oil-fired steam generating units, and base load oil-fired steam generating units. The final definitions of these subcategories are discussed in section VII.D.1 of this preamble. The final presumptive standards of performance are based on degrees of emission limitation that units are currently achieving, consistent with the proposed BSER of routine methods of operation and maintenance, which amounts to a proposed degree of emission limitation of no increase in emission rate.

For natural gas-fired steam generating units, the EPA proposed fixed presumptive standards of 1,500 lb CO_2/MWh-gross for intermediate load units (solicited comment on values between 1,400 and 1,600 lb/MWh-gross) and 1,300 lb CO_2/MWh-gross for base load units (solicited comment on values between 1,250 and 1,400 lb CO_2/MWh-gross). For oil-fired steam generating units, the EPA proposed fixed presumptive standards of 1,500 lb CO_2/MWh-gross for intermediate load units (solicited comment on values between 1,400 and 2,000 lb/MWh-gross) and 1,300 lb CO_2/MWh-gross for base load units (solicited comment on values between 1,250 and 1,800 lb CO_2/MWh-gross).

The EPA is finalizing presumptive standards of performance for affected natural gas-fired and oil-fired steam generating units in lieu of methodologies that states would use to establish presumptive standards of performance. This is largely because of the low variability in emissions data at intermediate and base load for these units and relatively consistent performance between these units at

those load levels, as discussed in section VII.D of this preamble and detailed in the final TSD, *Natural Gas- and Oil-fired Steam Generating Units,* which supports the establishment of a generally applicable standard of performance.

For intermediate load natural gas-fired units (annual capacity factors greater than or equal to 8 percent and less than 45 percent), annual emission rates are less than 1,600 lb CO_2/MWh-gross for more than 95 percent of units. Therefore, the EPA is finalizing the presumptive standard of performance of an annual calendar-year emission rate of 1,600 lb CO_2/MWh-gross for these units.

For base load natural gas-fired units (annual capacity factors greater than or equal to 45 percent), annual emission rates are less than 1,400 lb CO_2/MWh-gross for more than 95 percent of units. Therefore, the EPA is finalizing the presumptive standard of performance of an annual calendar-year emission rate of 1,400 lb CO_2/MWh-gross for these units.

In the continental U.S., there are few if any oil-fired steam generating units that operate with intermediate or high utilization. Liquid-oil-fired steam generating units with 24-month capacity factors less than 8 percent do qualify for a work practice standard in lieu of emission requirements under the MATS (40 CFR part 63, subpart UUUUU). If oil-fired units operated at higher annual capacity factors, it is likely they would do so with substantial amounts of natural gas-firing and have emission rates that are similar to steam generating units that fire only natural gas at those levels of utilization. There are a few natural gas-fired steam generating units that are near the threshold for qualifying as oil-fired units (*i.e.,* firing more than 15 percent oil in a given year) but that on average fire more than 90 percent of their heat input from natural gas. Therefore, the EPA is finalizing the same presumptive standards of performance for oil-fired steam generating units as for natural gas-fired units (1,400 lb CO_2/MWh-gross for base load units and 1,600 lb CO_2/MWh-gross for intermediate load units).

Lastly, the EPA is finalizing uniform fuels as the BSER for low load natural gas and oil-fired steam generating units. The EPA is finalizing degrees of emission limitation defined by 130 lb CO_2/MMBtu for low load natural gas-fired steam generating units and 170 lb CO_2/MMBtu for low load oil-fired steam generating units, and presumptively approvable standards consistent with those values.

Comment: One commenter stated that the EPA should instead allow states to define standards using a source's baseline emission rate, with some additional flexibilities to account for changes in load.[916] The commenter also requested that, if the EPA were to finalize presumptive standards, then the higher values that the EPA solicited comment on for natural gas-fired units should be finalized. The commenter similarly requested that, if the EPA were to finalize presumptive standards, then the higher values that the EPA solicited comment on for oil-fired units should be finalized—however, the commenter also noted that its two sources that are currently oil-firing operate below an 8 percent annual capacity factor and would therefore not be subject to the intermediate load or base load presumptive standard.

Response: The EPA is finalizing presumptive standards for natural gas-fired steam generating units of 1,400 lb CO_2/MWh-gross for base load units and 1,600 lb CO_2/MWh-gross for intermediate load units. The EPA is finalizing the same standards for oil-fired steam generating units for the reasons discussed in the preceding text. Few, if any, oil-fired units operate as intermediate load or base load units, as acknowledged by the commenter. Those oil-fired units that have operated near the threshold for intermediate load have typically fired a large proportion of natural gas and operated at emission rates consistent with the final presumptive standards.

c. Compliance Dates

This section summarizes information on the compliance dates, or the first date on which the standard of performance applies, that the EPA is finalizing for each subcategory. As discussed in section X.C.1.b, compliance is required to be demonstrated on an annual (*i.e.,* calendar year) basis.

The EPA proposed a compliance date of January 1, 2030, for all affected steam generating units. As discussed in section VII.C.1.a.i(E) of this preamble, the EPA received comments that this compliance date was not achievable for sources in the long-term coal-fired EGU subcategory that would be installing CCS. In response to those comments, the EPA reevaluated the information and timeline for CCS installation and is finalizing a compliance date of January 1, 2032, for the long-term coal-fired subcategory. The Agency is finalizing a compliance date of January 1, 2030, for units in the medium-term coal-fired subcategory as well as for natural gas- and oil-fired steaming generating units.

The EPA refers to January 1, 2030, and January 1, 2032, as ''compliance dates,'' ''final compliance dates,'' and ''initial compliance dates'' in various parts of this preamble. In each case, the EPA means that this is the date on which affected EGUs must start monitoring and reporting their emissions and other relevant data for purposes of demonstrating compliance with their standards of performance under these emission guidelines. Affected EGUs demonstrate compliance on a calendar year basis, *i.e.,* the compliance period for affected EGUs is 1 calendar year. Therefore, affected EGUs will not have to demonstrate that they are achieving their standards of performance on January 1, 2030, or January 1, 2032, as that demonstration is made only at the end of the compliance period, *i.e.,* at the end of the calendar year. But, again, these are the dates on which affected EGUs in the relevant subcategories must start monitoring and reporting for purposes of their future compliance demonstrations with their standards of performance.

d. Compliance Date Extension Mechanism

The EPA is finalizing provisions that allow states to include a mechanism to extend the compliance date for certain affected EGUs in their state plans. This mechanism is only available for situations in which an affected EGU encounters a delay in installation of a control technology that makes it impossible to commence compliance by the date specified in section X.C.1.c of this preamble. The owner or operator must provide documentation of the circumstances that precipitated the delay (or the anticipated delay) and demonstrate that those circumstances were or are entirely beyond the owner or operator's control and that the owner or operator has no ability to remedy the delay. These circumstances may include, but are not limited to, permitting-related delays or delays in delivery or construction of parts necessary for installation or implementation of the control technology.

The EPA received extensive comment requesting a mechanism to extend the compliance date for affected EGUs installing a control technology to address situations in which the owner or operator of the affected EGU encounters a delay outside of their control. Several industry commenters noted the potential for such delays due to, among other reasons, supply chain constraints, permitting processes, and/or environmental assessments as well as

[916] See Document ID No. EPA–HQ–OAR–2023–0072–0806.

delays in deployment of supporting infrastructure like pipelines. These commenters explained that an extension mechanism could provide greater regulatory certainty for owners and operators. In light of this feedback and acknowledgment that there may be circumstances outside of owners/operators' control that impact their ability to meet the compliance dates in these emission guidelines, the EPA believes that it is reasonable to provide a consistent and transparent means of allowing a limited extension of the compliance deadline where an affected EGU has demonstrated such an extension is needed for installation of controls. This mechanism is intended to address delays in implementation—not to provide more time to assess the compliance strategy (*i.e.,* the type of technology or subcategory assignment) for the affected EGU, as some commenters suggested; those decisions are to be made at the time of state plan approval.

The compliance date extension mechanism is consistent with both CAA section 111 and these emission guidelines. Consistent with the statutory purpose of remedying dangerous air pollution, state plans must generally provide for compliance with standards of performance as expeditiously as practicable but no later than specified in the emission guidelines. 40 CFR 60.24a(c). As discussed in sections VII.C.1.a.i.(E) and VII.C.2.b.i(C), the EPA has determined compliance timelines in these emission guidelines consistent with achieving emission reductions as expeditiously as practicable given the time it takes to install the BSER technologies for the respective subcategories. The compliance dates are designed to accommodate the process steps and timeframes that the EPA reasonably anticipates will apply to affected EGUs. This extension mechanism acknowledges that circumstances entirely outside the control of the owners or operators of affected EGUs may extend the timeframe for installation of control technologies beyond what the EPA reasonably expects for the subcategories as a general matter. Thus, so long as this extension mechanism is limited to circumstances that cannot be reasonably controlled or remedied by states or affected EGUs and that make it impossible to achieve compliance by the dates specified in these emission guidelines, its use is consistent with achieving compliance as expeditiously as practicable.

The EPA is establishing parameters, described in this subsection, for the features of this mechanism (*e.g.,* documentation, time limitation). Within these parameters, states should consider state-specific circumstances related to the implementation and enforcement of this mechanism in their state plans. Importantly, in order to provide compliance date extensions that do not require a state plan revision available to affected EGUs, states must include the mechanism in their proposed state plans that are provided for public comment and meaningful engagement (as well as in the final state plan submitted to the EPA), and the circumstances for and consequences of using this mechanism must be clearly spelled out and bounded. States are not required to include this mechanism in their state plans; absent its inclusion, states must submit a state plan revision in order to extend a compliance schedule that has been approved into a plan.

First, state plans must provide that a compliance date extension through this mechanism is available only for affected EGUs that are installing add-on controls. Affected EGUs that intend to comply without installing additional control technologies—including, but not limited to, oil and gas-fired steam generating EGUs—should not experience the types of installation or implementation delays that this mechanism is intended to address. Second, state plan mechanisms must provide that to receive a compliance date extension, the owner or operator of an affected EGU is required to demonstrate to the state air pollution control agency, and provide supporting documentation to establish, the basis for and plans to address the delay. For each affected EGU, this demonstration must include (1) confirmation that the affected EGU has met the relevant increments of progress up to the point of the delay, including any permits obtained and/or contracts entered into for the installation of control technology, (2) documentation, such as invoices or correspondence with permitting authorities, vendors, etc., of the circumstances of the delay and that the delay is due to the action, or lack thereof, of a third party (*e.g.,* supplier or permitting authority), and that the owner or operator of the affected EGU has itself acted consistent with achieving timely compliance (*e.g.,* in applying for permits with all necessary information or contracting in sufficient time to perform in accordance with required schedules), and (3) plans for addressing the circumstances and remedying the delay as expeditiously as practicable, including updated dates for the final increment of progress corresponding to the compliance date as well as any other increments that are outstanding at the time of the demonstration. These requirements for documentation are intended to ensure, *inter alia,* that the owner or operator has made all reasonable efforts to achieve timely compliance and that the circumstances for granting an extension are not speculative but are rather based on delays the affected EGU is currently experiencing or is reasonably certain to experience.

The extended compliance date must be as expeditiously as practicable and the maximum time allowed for this extension is 1 year beyond the compliance date specified for the affected EGU by the state plan. Several commenters suggested that a 1-year extension was appropriate. If the delay is anticipated to be longer than 1 year, states can provide for the use of this mechanism for up to 1 year but should also initiate a state plan revision if necessary to provide an updated compliance date through consideration of RULOF, subject to EPA approval of the plan revision.

The state air pollution control agency is charged with approving or disapproving a compliance date extension request based on its written determination that the affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation. All documentation for the extension request must be submitted by the owner or operator of the affected EGU to the state air pollution control agency no later than 6 months prior to the compliance date provided in these emission guidelines. The owner or operator of the affected EGU must also notify the relevant EPA Regional Administrator of their compliance date extension request at the time of the submission of the request. The owner or operator of the affected EGU must also post their application for the compliance date extension request to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, when they submit the request to the state air pollution control agency. The state air pollution control agency must notify the relevant EPA Regional Administrator of any determination on an extension request and the new compliance date for any affected EGU(s) with an approved extension at the time of the determination on the extension request. The owner or operator of the affected EGU must also post the state's determination on the compliance extension request to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, upon receipt of the determination, and, if the request is

approved, update information on the website related to the compliance date and increments of progress dates within 30 days of the receipt of the state's approval.

2. Remaining Useful Life and Other Factors

Under CAA section 111(d), the EPA is required to promulgate regulations under which states submit plans that ''establish[] standards of performance for any existing source'' and ''provide for the implementation and enforcement of such standards of performance.'' While states establish the standards of performance, there is a fundamental obligation under CAA section 111(d) that such standards reflect the degree of emission limitation achievable through the application of the BSER, as determined by the EPA.[917] The EPA identifies this degree of emission limitation as part of its emission guideline. 40 CFR 60.22a(b)(5). Thus, as described in section X.C.2 of this preamble, the EPA is providing methodologies for states to follow in determining and applying presumptively approvable standards of performance to affected EGUs in each of the subcategories covered by these emission guidelines. In general, the standards of performance that states establish for designated facilities must be no less stringent than the presumptively approvable standards of performance specified in these emission guidelines. 40 CFR 60.24a(c).

However, CAA section 111(d)(1) also requires that the EPA's regulations permit the states, in applying a standard of performance to any particular designated facility, to ''take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies.'' The EPA's implementing regulations under 40 CFR 60.24a allow a state to consider a particular designated facility's remaining useful life and other factors (''RULOF'') in applying to that facility a standard of performance that is less stringent than the presumptive level of stringency in the applicable emission guideline, or a compliance schedule that is longer than prescribed by that emission guideline.

In the proposal, the EPA indicated that it had recently proposed, in a separate rulemaking, to clarify the general implementing regulations governing the application of RULOF. The Agency further explained that the revised RULOF regulations, as finalized in that separate rulemaking, would apply to these emission guidelines. The revisions to the implementing regulations' RULOF provisions were finalized in November 2023, with some changes in response to public comments relative to proposal. As provided by 40 CFR 60.20a(a) and (a)(1) and indicated in the proposal, the RULOF provisions in 40 CFR 60.24a, as revised in the November 2023 final rule, will govern the use of RULOF to provide less stringent standards of performance or longer compliance schedules under these emission guidelines. The EPA is not superseding any provision of the RULOF regulations at 40 CFR 60.24a in these emission guidelines.

As explained in the preamble to the final rule, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clear Air Act Section 111(d),* the EPA has interpreted the RULOF provision of CAA section 111(d)(1) as allowing states to apply a standard of performance that is less stringent than the degree of emission limitation in the applicable emission guideline, or a longer compliance schedule, to a particular facility based on that facility's remaining useful life and other factors. The use of RULOF to deviate from an emission guideline is available only when there are fundamental differences between the circumstances of a particular facility and the information the EPA considered in determining the degree of emission limitation or the compliance schedule, and those fundamental differences make it unreasonable for the facility to achieve the degree of emission limitation or meet the compliance schedule in the emission guideline. This ''fundamentally different'' standard is consistent with the statutory purpose of reducing dangerous air pollution under CAA section 111; the statutory framework under which, to achieve that purpose, the EPA is directed to determine the degree of emission under CAA section 111(a)(1); and the understanding that RULOF is intended as a limited variance from the EPA's determination to address unusual circumstances at particular facilities.[918]

The relevant consideration for states contemplating the use of RULOF to apply a less stringent standard of performance is whether a designated facility can reasonably achieve the degree of emission limitation in the applicable emission guideline, not whether it can implement the system of emission reduction the EPA determined is the BSER. That is, if a designated facility cannot implement the BSER but can reasonably achieve the specified degree of emission limitation using a different system of emission reduction, the state cannot use RULOF to apply a less stringent standard of performance to that facility.

If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular facility cannot reasonably achieve the degree of emission limitation or compliance schedule determined by the EPA in these emission guidelines, the state may then apply a less stringent standard of performance or longer compliance schedule. The process for doing so is laid out in 40 CFR 60.24a(f). Critically, standards of performance and compliance schedules pursuant to RULOF must be no less stringent, or no longer, than is necessary to address the fundamental difference between the information the EPA considered and the particular facility that was the basis for invoking RULOF under 40 CFR 60.24a(e). In determining a less stringent standard of performance, the state must, to the extent necessary, evaluate the systems of emission reduction identified in the emission guidelines using the factors and evaluation metrics the EPA considered in assessing those systems, including technical feasibility, the amount of emission reductions, the cost of achieving such reductions, any non-air quality health and environmental impacts, and energy requirements. States may also consider, as justified, other factors specific to the facility that were the basis for invoking RULOF under 40 CFR 60.24a(e), as well as additional systems of emission reduction.

The RULOF provision at 40 CFR 60.24a(g) states that, where the basis of a less stringent standard of performance is an operating condition within the control of a designated facility, the state plan must include such operating condition as an enforceable requirement. The state plan must also include requirements, such as for monitoring, reporting, and recordkeeping, for the implementation and enforcement of the condition. This is relevant in the case of, for example, less stringent standards of performance that are based on a particular designated facility's remaining useful life or utilization.

Finally, the general implementing regulations provide that states may always adopt and enforce, as part of their state plans, standards of

[917] *West Virginia* v. *EPA,* 597 U.S. 697, 720 (2022) (''In devising emissions limits for power plants, EPA first 'determines' the 'best system of emission reduction' that—taking into account cost, health, and other factors—it finds 'has been adequately demonstrated.' The Agency then quantifies 'the degree of emission limitation achievable' if that best system were applied to the covered source.'') (internal citations omitted).

[918] See, *e.g.,* 88 FR 80512 (November 17, 2023).

performance that are more stringent than the degree of emission limitation determined by the EPA and compliance schedules that require final compliance more quickly than specified in the applicable emission guidelines. 40 CFR 60.24a(i). States do not have to use the RULOF provisions in 40 CFR 60.24a(e)–(h) to apply a more stringent standard of performance or faster compliance schedule.

The EPA notes that there were a number of RULOF provisions proposed as additions to the general implementation regulations in subpart Ba and discussed in the proposed emission guidances that the EPA did not finalize as part of that separate rulemaking. Any proposed RULOF requirements that were not finalized in 40 CFR 60.24a are likewise not being finalized in this action and do not apply as requirements under these emission guidelines. However, two considerations in particular remain relevant to states' development of plans despite not being finalized as requirements: consideration of communities most impacted by and vulnerable to the health and environmental impacts of an affected EGU that is invoking RULOF, and the need to engage in reasoned decision making that is supported by information and a rationale that is included in the state plan.[919]

As explained in the preamble to the November 2023 final rule revising subpart Ba, consideration of health and environmental impacts is inherent in consideration of two factors, the non-air quality health and environmental impacts and amount of emission reduction, that the EPA considers under CAA section 111(a)(1). Therefore, a state considering whether a variance from the EPA's degree of emission limitation is appropriate will necessarily consider the potential impacts and benefits of control to communities impacted by an affected EGU that is potentially receiving a less stringent standard of performance.[920] Additionally, as discussed in section X.E.1.b.i of this preamble, the general implementing regulations for CAA section 111(d) in subpart Ba require states to submit, with their state plans or plan revisions, documentation that they have conducted meaningful engagement with pertinent stakeholders and/or their representative in the plan (or plan revision) development process. 40 CFR 60.23a(i). The application of a less stringent standard of performance or longer compliance schedule pursuant to RULOF can impact the effects a state plan has on pertinent stakeholders, which include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of a state plan or plan revision. See 40 CFR 60.21a(l). Therefore, the potential application of less stringent standards of performance or longer compliance schedule should be part of a state's meaningful engagement on a state plan or plan revision.

Similarly, the EPA emphasized in the preamble to the November 2023 final rule revising subpart Ba that states carry the burden of making any demonstrations in support of less-stringent standards of performance pursuant to RULOF in developing their plans. As a general matter, states always bear the responsibility of reasonably documenting and justifying the standards of performance in their plans. In order to find a standard of performance satisfactory, the EPA must be able to ascertain, based on the information and analysis included in the state plan submission, that the standard meets the statutory and regulatory requirements.[921]

Comment: Multiple commenters expressed support for the EPA's proposed approach to RULOF, including its framework for ensuring that less stringent standards of performance and longer compliance schedules are limited to unique circumstances that reflect fundamental differences from the circumstances that the EPA considered, and that such standards do not undermine the overall effectiveness of the emission guidelines. These commenters also noted that the proposed RULOF approach is consistent with CAA section 111(d). However, other commenters argued that the EPA lacks authority to put restrictions on how states consider RULOF to apply less stringent standards of performance or longer compliance schedules. Some commenters stated that the EPA's framework for the consideration of RULOF runs counter to section 111's framework of cooperative federalism and that the EPA has a limited role of determining BSER for the source category while the statute reserves significant authority for the states to establish and implement standards of performance. One commenter elaborated that the broad discretion given to states to establish standards of performance gives the EPA only a limited role in reviewing states' RULOF demonstrations.

Response: The provisions that will govern states' use of RULOF under these emission guidelines are contained in the part 40, subpart Ba CAA section 111(d) implementing regulations. Following proposal of these emission guidelines, the EPA finalized revisions to the subpart Ba RULOF provisions in a separate rulemaking. Any comments on these generally applicable provisions, including the EPA's authority to promulgate and implement them and consistency with the cooperative federalism framework of CAA section 111(d), are outside the scope of this action. The EPA has, however, considered and responded to comments that concern the application of these generally applicable RULOF provisions under these particular emission guidelines.

Comment: Several commenters spoke to the role of RULOF given the structure of the proposed subcategories for coal-fired steam generating affected EGUs. Some commenters supported the EPA's statement that, given the four proposed subcategories based on affected EGUs' intended operating horizons, the Agency did not anticipate that states would be likely to need to invoke RULOF based on a particular affected EGU's remaining useful life. In contrast, other commenters stated that the EPA was attempting to unlawfully preempt state consideration of RULOF. Some noted that, regardless of the approach to subcategorization, a particular source may still present source-specific considerations that a state may consider relevant when applying a standard of performance. One commenter referred to RULOF as a way for states to ''modify'' subcategories to address the circumstances of particular affected EGUs.

Response: As explained in section VII.C of this preamble, the structure of the subcategories for coal-fired steam generating affected EGUs under these final emission guidelines differs from the four subcategories that the EPA proposed. The EPA is finalizing just two subcategories for coal-fired EGUs: the long-term subcategory and the medium-term subcategory. Under these circumstances, the justification for the EPA's statement at proposal that it is unlikely that states would need to invoke RULOF based on a coal-fired steam generating affected EGU's remaining useful life no longer applies. Consistent with 40 CFR 60.24a(e) and the Agency's explanation in the proposal, states have the ability to

[919] The other RULOF provisions that the EPA proposed as additions to 40 CFR 60.24a but did not finalize are related to setting imminent and outermost dates for the consideration of remaining useful life and consideration of RULOF to apply more stringent standards of performance. See 88 FR 80480, 80525, 80529 (November 17, 2023).

[920] 88 FR 80528 (November 17, 2023).

[921] See *id.* at 80527.

consider, *inter alia,* a particular source's remaining useful life when applying a standard of performance to that source.[922]

Moreover, the EPA is clarifying that RULOF may be used to particularize the compliance obligations for an affected EGU when a state demonstrates that it is unreasonable for that EGU to achieve the applicable degree of emission limitation or compliance schedule determined by the EPA. Invocation of RULOF does not have the effect of modifying the subcategory structure or creating a new subcategory for a particular affected EGU. That EGU remains in the applicable subcategory. As explained elsewhere in this section of the preamble, the particularized compliance obligations must differ as little as possible from the presumptive standard of performance and compliance schedule for the subcategory into which the affected EGU falls under these emission guidelines.

Comment: One commenter requested that the EPA identify situations in which it is reasonable to deviate from the presumptive standards of performance in the emission guidelines and include presumptively approvable approaches for states to use when invoking RULOF. The commenter noted that this would reduce the regulatory burden on states developing and submitting plans. Another commenter, however, stated that the EPA should not provide any presumptively approvable standard, criteria, or analytic approach for states seeking to use RULOF. This commenter explained that the premise of source-specific variances under RULOF is that they reflect circumstances that are unique to a particular unit and fundamental differences from the general case, and that it would be inappropriate to offer a generic rubric for approving variances separate from the particularized facts of each case.

Response: The EPA is not identifying circumstances in which it would be reasonable to deviate from its determinations or providing presumptively approvable approaches to invoking RULOF in these emission guidelines. For this source category—fossil-fuel fired steam generating EGUs—in particular, the circumstances and characteristics of affected EGUs and the control strategies the EPA has identified as BSER are extremely context- and source-specific. In order to invoke RULOF for a particular affected EGU, a state must demonstrate that it is unreasonable for that EGU to reasonably achieve the applicable degree of emission limitation or compliance schedule. Given the diversity of sizes, ages, locations, process designs, operating conditions, *etc.,* of affected EGUs, it is highly unlikely that the circumstances that result in one affected EGU being unable to reasonably achieve the applicable presumptive standard or compliance schedule would apply to any other affected EGU. Further, the RULOF provisions of subpart Ba provide clarity for and guidance to states as to what constitutes a satisfactory less-stringent standard of performance under these emission guidelines.

While the EPA is not providing presumptively approvable circumstances or analyses for RULOF in these emission guidelines, it is providing information and analysis that states can leverage in making any determinations pursuant to the RULOF provisions. As explained elsewhere in this section of the preamble, the EPA expects that states will be able to particularize the information it is providing in section VII of this preamble and the final Technical Support Documents for the circumstances of any affected EGUs for which they are considering RULOF, thereby decreasing the analytical burdens.

Comment: Several commenters stated that the proposed emission guidelines did not provide adequate time for RULOF analyses.

Response: As noted above, the EPA expects states to leverage the information it is providing in section VII of this preamble and the final Technical Support Documents in conducting any RULOF analyses under these emission guidelines. In particular, the Agency believes states will be able to use the information it is providing on available control technologies for affected EGUs, technical considerations, and costs given different amortization periods and particularize it for the purpose of conducting any analyses pursuant to 40 CFR 60.24a(e) and (f). Additionally, as discussed in section X.C.2.b of this preamble, the regulatory provisions for RULOF under subpart Ba provide a framework for determining less stringent standards of performance that have the practical effect of minimizing states' analytical burdens. Given the EPA's consideration of affected EGU's circumstances and operational characteristics in designing these emission guidelines, the Agency does not anticipate that states will be in the position of conducting numerous RULOF analyses as part of their state planning processes. The EPA therefore believes that states will have sufficient time to consider RULOF and conduct any RULOF analyses under these emission guidelines.

a. Threshold Requirements for Considering RULOF

The general implementing regulations of 40 CFR part 60, subpart Ba, provide that a state may apply a less stringent standard of performance or longer compliance schedule than otherwise required under the applicable emission guidelines based on consideration of a particular source's remaining useful life and other factors. To do so, the state must demonstrate for each designated facility (or class of such facilities) that the facility cannot reasonably achieve the degree of emission limitation determined by the EPA (*i.e.,* the presumptively approvable standard of performance) based on: (1) Unreasonable cost resulting from plant age, location, or basic process design, (2) physical impossibility or technical infeasibility of installing the necessary control equipment, or (3) other factors specific to the facility. In order to determine that one or more of these circumstances has been met, the state must demonstrate that there are fundamental differences between the information specific to a facility (or class of such facilities) and the information the EPA considered in the applicable emission guidelines that make achieving the degree of emission limitation or compliance schedule in those guidelines unreasonable for the facility.

For each subcategory of affected EGUs in these emission guidelines, the EPA determined the degree of emission limitation achievable through application of the BSER by considering information relevant to each of the factors in CAA section 111(a)(1): whether a system of emission reduction is adequately demonstrated for the subcategory, the costs of a system of emission reduction, the non-air quality health and environmental impacts and energy requirements associated with a system of emission reduction, and the extent of emission reductions from a system.[923] As noted above, the relevant consideration for invoking RULOF is whether an affected EGU can reasonably achieve the presumptive standard of

[922] See 88 FR 33383 (invoking RULOF based on a particular coal-fired EGU's remaining useful life ''is not prohibited under these emission guidelines'').

[923] The EPA also considered expanded use and development of technology in determining the BSER for each subcategory. However, as this consideration is not necessarily relevant at the scale of a particular source for which a less stringent standard of performance is being considered, it is not addressed here.

performance for the applicable subcategory, as opposed to whether it can implement the BSER. In determining the BSER the EPA found that certain costs, impacts, and energy requirements were, on balance, reasonable for affected EGUs; it is therefore reasonable to assume that the same costs, impacts, and energy requirements would be equally reasonable in the context of other systems of reduction, as well. Therefore, the information the EPA considered in relation to each of these factors is the baseline for consideration of RULOF regardless of the system of emission reduction being considered.

The EPA is providing presumptive standards of performance in these emission guidelines in the form of rate-based emission limitations. Thus, the focus for states considering whether a particular affected EGU has met the threshold for a less stringent standard of performance pursuant to RULOF is whether that affected EGU can reasonably achieve the applicable rate-based presumptive standard of performance in these emission guidelines.

Within each of the statutory factors it considered in determining the BSER, the Agency considered information using one or more evaluation metrics. For example, for both the long-term and medium-term coal-fired steam generating EGUs the EPA considered cost in terms of dollars/ton CO_2 reduced and increases in levelized costs expressed as dollars per MWh electricity generation. Under the non-air quality health and environmental impacts and energy requirements factor, the EPA considered non-greenhouse gas emissions and energy requirements in terms of parasitic load and boiler efficiency, in addition to evaluation metrics specific to the systems being evaluated for each subcategory. For the full range of factors, evaluation metrics, and information the EPA considered with regard to the long-term and medium-term coal-fired steam generating EGU subcategories, see section VII.D.1 and VII.D.2 of this preamble.

Although the considerations for invoking RULOF described in 40 CFR 60.24a(e) are broader than just unreasonable cost of control, much of the information the EPA considered in determining the BSER, and therefore many of the circumstances states might consider in determining whether to invoke RULOF, are reflected in the cost consideration. Where possible, states should reflect source-specific considerations in terms of cost, as it is an objective and replicable metric for comparison to both the EPA's information and across affected EGUs and states.[924] For example, consideration of pipeline length needed for a particular affected EGU is best reflected through consideration of the cost of that pipeline. In particular, consideration of the remaining useful life of a particular affected EGU should be considered with regard to its impact on costs. In determining the BSER, the EPA considers costs and specifically annualized costs associated with payment of the total capital investment associated with the BSER. An affected EGU's remaining useful life and associated length of the capital recovery period can have a significant impact on annualized costs. States invoking RULOF based on an affected EGU's remaining useful life should demonstrate that the annualized costs of applying the degree of emission limitation achievable through application of the BSER for a source with a short remaining useful life are fundamentally different from the costs that the EPA found were reasonable. For purposes of determining the annualized costs for an affected EGU with a shorter remaining useful life, the EPA considers the amortization period to begin at the compliance date for the applicable subcategory.

States considering the use of RULOF to provide a less stringent standard of performance for a particular EGU must demonstrate that the information relevant to that EGU is fundamentally different from the information the EPA considered. For example, in determining the degree of emission limitation achievable through the application of co-firing for medium-term coal-fired steam generating EGUs, the EPA found that costs of $71/ton CO_2 reduced and $13/MWh are reasonable. A state seeking to invoke RULOF for an affected coal-fired steam generating EGU based on unreasonable cost of control resulting from plant age, location, or basic process design would therefore, pursuant to 40 CFR 60.24a(e), demonstrate that the costs of achieving the applicable degree of emission limitation for that particular affected EGU are fundamentally different from $71/ton CO_2 reduced and/or $13/MWh.

Any costs that the EPA has determined are reasonable for any BSER for affected EGUs under these emission guidelines would not be an appropriate basis for invoking RULOF. Additionally, costs that are not fundamentally different from costs that the EPA has determined are or could be reasonable for sources would also not be an appropriate basis for invoking RULOF. Thus, costs that are not fundamentally different from, *e.g.,* $18.50/MWh (the cost for installation of wet-FGD on a 300 MW coal-fired steam generating unit, used for cost comparison in section VIII.D.1.a.ii of this preamble) would not be an appropriate basis for invoking RULOF under these emission guidelines. On the other hand, costs that constitute outliers, *e.g.,* that are greater than the 95th percentile of costs on a fleetwide basis (assuming a normal distribution) would likely represent a valid demonstration of a fundamental difference and could be the basis of invoking RULOF.

Importantly, the costs evaluated in BSER determinations are, in general, based on average values across the fleet of steam generating units. Those BSER cost analysis values represent the average of a distribution of costs including costs that are above or below the average representative value. On that basis, implicit in the determination that those average representative values are reasonable is the determination that a significant portion of the unit-specific costs around those average representative values are also reasonable, including some portion of those unit-specific costs that are above but not significantly different than the average representative values. That is, the cost values the EPA considered in determining the BSER should not be considered bright-line upper thresholds between reasonable and unreasonable costs. Moreover, the examples in this discussion are provided merely for illustrative purposes; because each RULOF demonstration must be evaluated based on the facts and circumstances relevant to a particular affected EGU, the EPA is not setting any generally applicable thresholds or providing presumptively approvable approaches for determining what constitutes a fundamental difference in cost or any other consideration under these emission guidelines. The Agency will assess each use of RULOF in a state plan against the applicable regulatory requirements; however, the EPA is providing examples in this preamble in response to comments requesting that it provide further clarity and guidance on what constitutes a satisfactory use of RULOF.

Under 40 CFR 60.24a(e)(1)(iii), states may also consider ''other factors specific to the facility.'' Such ''other factors'' may include both factors (categories of information) that the EPA did not consider in determining the degree of emission limitation achievable through

[924] The EPA reiterates that states are not precluded from considering information and factors other than costs under 40 CFR 60.24a(e)(ii) and (iii).

application of the BSER and additional evaluation metrics (ways of considering a category of information) that the EPA did not consider in its analysis. To invoke RULOF based on consideration of ''other factors,'' a state must demonstrate that a factor makes it unreasonable for the affected EGU to achieve the applicable degree of emission limitation in these emission guidelines.

The general implementing regulations of subpart Ba provide that states may invoke RULOF for a class of facilities. In the preamble to the subpart Ba final rule, the EPA explained that ''invoking RULOF and providing a less-stringent standard [of] performance or longer compliance schedule for a class of facilities is only appropriate where all the facilities in that class are similarly situated in all meaningful ways. That is, they must not only share the circumstance that is the basis for invoking RULOF, they must also share all other characteristics that are relevant to determining whether they can reasonably achieve the degree of emission limitation determined by the EPA in the applicable EG. For example, it would not be reasonable to create a class of facilities for the purpose of RULOF on the basis that the facilities do not have space to install the EPA's BSER control technology if some of them are able to install a different control technology to achieve the degree of emission limitation in the EG.'' [925] Given that individual fossil fuel-fired steam generating EGUs are very unlikely to be similarly situated with regard to all of the characteristics relevant to determining the reasonableness of meeting a degree of emission limitation, the EPA believes it would not likely be reasonable for a state to invoke RULOF for a class of facilities under these emission guidelines. That is, because there are relatively few affected EGUs in each subcategory and because each EGU is likely to have a distinct combination of size, operating process, footprint, geographic location, *etc.,* it is highly unlikely that the same threshold analysis would apply to two or more units.

i. Invoking RULOF for Long-Term Coal-Fired Steam Generating EGUs

In determining the BSER for the long-term coal-fired steam generating EGUs, the EPA considered several evaluation metrics specific to CCS. However, affected EGUs are not required to implement CCS to comply with their standards of performance. To the extent a state is considering whether it is reasonable for a particular affected EGU in this subcategory to achieve the degree of emission limitation using CCS as the control strategy, the state would consider whether that affected EGU's circumstances are fundamentally different from the evaluation metrics and information the EPA considered in these emission guidelines. If a state is considering whether it is reasonable for an affected EGU to achieve the degree of emission limitation for long-term coal-fired steam generating EGUs through some other control strategy, certain of the evaluation metrics and information the EPA considered, such as overall costs and energy requirements, would be relevant while other metrics or information may or may not be.

As discussed above, the EPA considered costs in terms of $/ton CO_2 reduced and $/MWh. The Agency broke down its cost consideration for CCS into capture costs and CO_2 transport and sequestration costs, as discussed in sections VIII.D.1.a.ii.(A) and (B) of this preamble. The EPA also considered the availability of the IRC section 45Q tax credit in evaluating the cost of CCS for affected EGUs, and finally, evaluated the impacts of two different capacity factor assumptions on costs. Similarly, the Agency considered a number of evaluation metrics specific to CCS under the non-air quality health and environmental impacts and energy requirements factors, in addition to considering non-greenhouse gas emissions and parasitic/auxiliary energy demand increases and the net power output decreases. In particular, the EPA considered water use, CO_2 capture plant siting, transport and geologic sequestration, and impacts on the energy sector in terms of long-term structure and reliability of the power sector. A state may also consider other factors and circumstances that the EPA did not consider in its evaluation of CCS, to the extent such factors or circumstances are relevant to the reasonableness of achieving the associated degree of emission limitation.

As detailed in section VII.D.1.a.i of this preamble, the EPA has determined that CCS is adequately demonstrated for long-term coal-fired steam generating EGUs. The Agency evaluated the components of CCS both individually and in concurrent, simultaneous operation. If a state believes a particular affected EGU cannot reasonably implement CCS based on physical impossibility or technical infeasibility, the state must demonstrate that the circumstances of that individual EGU are fundamentally different from the information on CCS that the EPA considered in these emission guidelines.

ii. Invoking RULOF for Medium-Term Coal-Fired Steam Generating EGUs

As for the long-term coal-fired steam generating EGU subcategory, the EPA also considered evaluation metrics and information specific to the BSER, natural gas co-firing, for the medium-term subcategory. Again, similar to the long-term subcategory, certain generally applicable metrics and information that the EPA considered, *e.g.,* overall costs and energy requirements, will be relevant regardless of the control strategy a state is considering for an affected EGU in the medium-term subcategory. To the extent a state is considering whether it is reasonable for a particular affected EGU to reasonably achieve the presumptive standard of performance using natural gas co-firing as a control, the state should evaluate whether there is a fundamental difference between the circumstances of that EGU and the information the EPA considered. In considering costs for natural gas co-firing, the Agency took into account costs associated with adding new gas burners and other boiler modifications, fuel cost, and new natural gas pipelines. In considering non-air quality health and environmental impacts and energy requirements, the EPA addressed losses in boiler efficiency due to co-firing, as well as non-greenhouse gas emissions and impact on the structure of the energy sector. States may also consider other factors and circumstances that are relevant to determining the reasonableness of achieving the applicable degree of emission limitation.

iii. Invoking RULOF To Apply a Longer Compliance Schedule

Under 40 CFR 60.24a(c), ''final compliance,'' *i.e.,* compliance with the applicable standard of performance, ''shall be required as expeditiously as practicable but no later than the compliance times specified'' in the applicable emission guidelines, unless a state has demonstrated that a particular designated facility cannot reasonably comply with the specific compliance time per the RULOF provision at 40 CFR 60.24a(e). The EPA, in these emission guidelines, has detailed the amount of time needed for states and affected EGUs in the long-term and medium-term coal-fired steam generating EGU subcategories to comply with standards of performance using CCS and natural gas co-firing, respectively, in sections VII.C.1 and VII.C.2 of this preamble. These compliance times are based on information available for and applicable to the subcategories as a whole. The

[925] 88 FR 80517 (November 17, 2023).

Agency anticipates that some affected EGUs will be able to comply more expeditiously than on these generally applicable timelines. Similarly, there may be circumstances in which a particular EGU cannot reasonably comply with its standard of performance by the compliance date specified in these emission guidelines. In order to provide a longer compliance schedule, the state must demonstrate that there is a fundamental difference between the information the EPA considered for the subcategory as a whole and the circumstances of a particular EGU. These circumstances should not be speculative; the state must substantiate the need for a longer compliance schedule with documentation supporting that need and justifying why a certain component or components of implementation will take longer than the EPA considered in these emission guidelines. If a state anticipates that a process or activity will take longer than is typical for similarly situated EGUs within and outside the state or longer than it has historically, the state should provide an explanation of why it expects this to be the case as well as evidence corroborating the reasons and need for additional time. Consistent with 40 CFR 60.24a(c) and (e), states should not use the RULOF provision to provide a longer compliance schedule unless there is a demonstrated, documented reason at the time of state plan submission that a particular source will not be able to achieve compliance by the date specified in these emission guidelines. The EPA notes that it is providing a number of flexibilities in these final emission guidelines for states and sources if they find, subsequent to state plan submission, that additional time is necessary for compliance; states should consider these flexibilities in conjunction with the potential use of RULOF to provide a longer compliance schedule. A source-specific compliance date pursuant to RULOF must be no later than necessary to address the fundamental difference; that is, it must be as close to the compliance schedule provided in these emission guidelines as reasonably possible. Considerations specific to providing a longer compliance schedule to address reliability are addressed in section X.C.2.e.i of this preamble.

Comment: Several commenters stated that the EPA must respect the broad authority granted to states under the CAA and that while the EPA's information on various factors is helpful to states, states may readily deviate from the emission guidelines in order to account for source- and state-specific characteristics. The commenters argued that the EPA's general implementing regulations at 40 CFR 60.24a(c) recognize that states may consider factors that make application of a less stringent standard of performance or longer compliance time significantly more reasonable, and commenters stated that those factors should include, *inter alia,* cost, feasibility, infrastructure development, NSR implications, fluctuations in performance depending on load, state energy policy, and potential reliability issues. The commenters stated that states have the authority to account for consideration of other factors in various ways and that the EPA must defer to state choices, provided those choices are reasonable and consistent with the statute.

Response: Comments on states' use of RULOF vis-à-vis the EPA's determinations pursuant to CAA section 111(a)(1) in the applicable emission guidelines are outside the scope of this rulemaking.[926] Similarly, comments on the EPA's authority to review states' use of RULOF in state plans and the scope of that review are outside the scope of this rulemaking.[927] The EPA is also clarifying that, while the commenters are correct that the general implementing regulations at 40 CFR 60.24a(c) recognize that states may invoke RULOF to provide a less stringent standard of performance or longer compliance schedule, they also provide that, unless the threshold for the use of RULOF in 40 CFR 60.24a(e) has been met, ''standards of performance shall be no less stringent than the corresponding emission guideline(s) . . . and final compliance shall be required as expeditiously as practicable but no later than the compliance times specified'' in the emission guidelines. The threshold for invoking RULOF is when a state demonstrates that a particular affected EGU cannot reasonably achieve the degree of emission limitation determined by the EPA, based on one or more of the circumstances at 40 CFR 60.24a(e)(i)–(iii), because there are fundamental differences between the information the EPA considered in the emission guidelines and the information specific to the affected EGU. The ''significantly more reasonable'' standard does not apply to RULOF determinations under these emission guidelines.[928]

The EPA agrees that states have authority to consider ''other circumstances specific to the facility.'' States are uniquely situated to have knowledge about unit-specific considerations. If a unit-specific factor or circumstance is fundamentally different from the information the EPA considered and that difference makes it unreasonable for the affected EGU to achieve that degree of emission limitation or compliance schedule,[929] it is grounds for applying a less stringent standard of performance or longer compliance schedule. The EPA will review states' RULOF analyses and determinations for consistency with the applicable regulatory requirements at 40 CFR 60.24a(e)–(h).

Comment: Multiple commenters weighed in on the subject of cost metrics. Two commenters stated that the EPA should not require states to consider costs using the same metrics that it considered in the emission guidelines. These commenters explained that the unique circumstances of each unit mean that different metrics may be appropriate and should be allowed as long as the state plan provides a justification. Other commenters, however, supported the proposed requirement for states to consider costs using the same metrics as the EPA. Similarly, commenters differed on the example in the proposed rule preamble that costs that are greater than the 95th percentile of costs on a fleetwide basis would likely be fundamentally different from the fleetwide costs that the EPA considered in these emission guidelines. While one commenter believed that the 95th percentile may not be an appropriate threshold in all circumstances and should not be treated as an absolute, another commenter argued that the EPA should formalize the 95th percentile threshold as a requirement for states seeking to invoke RULOF based on unreasonable cost.

Response: The EPA believes that, in order to evaluate whether there is a fundamental difference between the cost information the EPA considered in these emission guidelines and the cost information for a particular affected EGU, it is necessary for states to evaluate costs using the same metrics that the EPA considered. However, states are not precluded from considering additional cost metrics alongside the two metrics used in these emission guidelines: $/ton of CO_2 reduced and $/MWh of electricity

[926] See 88 FR 80509–17 (November 17, 2023).

[927] See *id.* at 80526–27.

[928] 40 CFR 60.20a(a).

[929] ''Other factors'' may include facility-specific circumstances and factors that the EPA did not anticipate and consider in the applicable emission guideline that make achieving the EPA's degree of emission limitation unreasonable for that facility. 88 FR 80480, 80521 (November 17, 2023).

generated. States should justify why any additional cost metrics are relevant to determining whether a particular affected EGU can reasonably achieve the applicable degree of emission limitation.

The EPA did not state that a cost that is greater than the 95th percentile of fleetwide costs would necessarily justify invocation of RULOF. Nor did the EPA intend to suggest that such costs are the only way states can demonstrate that the costs for a particular affected EGU are fundamentally different. While it may be an appropriate benchmark in some cases, there are other ways for states to demonstrate that the cost for a particular affected EGU is an outlier. That is, the EPA is not requiring that the unit-specific costs be above the 95th percentile in order to demonstrate that they are fundamentally different from the costs the Agency considered in these emission guidelines. As discussed elsewhere in this section of the preamble, the diversity in circumstances of individual affected EGUs under these emission guidelines makes it infeasible for the EPA to *a priori* define a bright line for what constitutes reasonable versus unreasonable costs for individual units in these emission guidelines.

Comment: One commenter noted that the EPA should only approve the use of RULOF to provide a longer compliance schedule where there is clearly documented evidence (*e.g.,* receipts, invoices, actual site work) that a source is making best endeavors to achieve compliance as expeditiously as possible.

Response: The EPA believes this kind of evidence is strong support for providing a longer compliance schedule. The Agency further believes that states should show that the need to provide a longer compliance schedule is notwithstanding best efforts on the parts of all relevant parties to achieve timely compliance. The EPA is not, however, precluding the possibility that states could reasonably justify a longer compliance schedule based on other types of information or evidence.

b. Calculation of a Standard of Performance That Accounts for RULOF

If a state has demonstrated that a particular affected EGU is unable to reasonably achieve the applicable degree of emission limitation or compliance schedule under these emission guidelines per 40 CFR 60.24a(e), it may then apply a less stringent standard of performance or longer compliance schedule according to the process laid out in 40 CFR 60.24a(f). Pursuant to that process, the state must determine the standard of performance or compliance schedule that, respectively, is no less stringent or no longer than necessary to address the fundamental difference that was the basis for invoking RULOF. That is, the standard of performance or compliance schedule must be as close to the EPA's degree of emission limitation or compliance schedule as reasonably possible for that particular EGU.

The EPA notes that the proposed emission guidelines would have included requirements for how states determine less stringent standards of performance, including what systems of emission reduction states must evaluate and the order in which they must be evaluated. These proposed requirements were intended to ensure that states reasonably consider the controls that may qualify as a source-specific BSER.[930] However, the final RULOF provisions in subpart Ba for determining less stringent standards of performance differ from the proposed subpart Ba provisions in a way that obviates the need for the separate requirements proposed in these emission guidelines. First, as opposed to determining a source-specific BSER for sources that have met the threshold requirements for RULOF, states determine the standard of performance that is no less stringent than the EPA's degree of emission limitation than necessary to address the fundamental difference. Second, the process for determining such a standard of performance that the EPA finalized at 40 CFR 60.24a(f)(1) involves evaluating, to the extent necessary, the systems of emission reduction that the EPA identified in the applicable emission guidelines using the factors and evaluation metrics that the Agency considered in assessing those systems. Because the final RULOF provisions of subpart Ba create essentially the same process as the provisions the EPA proposed for determining a less stringent standard of performance under these emission guidelines, the EPA has determined it is not necessary to finalize those provisions here.

The EPA anticipates that states invoking RULOF for affected EGUs will do so because an EGU is in one of two circumstances: it is implementing the control strategy the EPA determined is the BSER but cannot achieve the degree of emission limitation in the emission guideline using that control (or any other system of emission reduction); or it is not implementing the BSER and cannot reasonably achieve the degree of emission limitation using any system of emission reduction.

If an affected EGU will be implementing the BSER but cannot meet the degree of emission limitation due to fundamental differences between the circumstances of that particular EGU and the circumstances the EPA considered in the emission guidelines, it may not be necessary for the state to evaluate other systems of emission reduction to determine the less stringent standard of performance. In this instance, the state and affected EGU would determine the degree of emission limitation the EGU can reasonably achieve, consistent with the requirement that it be no less stringent than necessary. That degree of emission limitation would be the basis for the less stringent standard of performance. For example, assume an affected EGU in the long-term coal-fired steam generating EGU subcategory is intending to install CCS and the state has demonstrated that it is not reasonably possible for the capture equipment at that particular EGU to achieve 90 percent capture of the mass of CO_2 in the flue gas (corresponding to an 88.4 percent reduction in emission rate), but it can reasonably achieve 85 percent capture. If the source cannot reasonably achieve an 88.4 percent reduction in emission rate using any other system of emission reduction, the state may apply a less stringent standard of performance that corresponds to 85 percent capture without needing to evaluate further systems of emission reduction.

In other cases, however, an affected EGU may not be implementing the BSER and may not be able to reasonably achieve the applicable degree of emission limitation (*i.e.,* the presumptive standard of performance) using any control strategy. In such situations, the state must determine the standard of performance that is no less stringent than necessary by evaluating the systems of emission reduction the EPA considered in these emission guidelines, using the factors and evaluation metrics the EPA considered in assessing those systems. States may also consider additional systems of emission reduction that the EPA did not identify but that the state believes are available and may be reasonable for a particular affected EGU.

The requirement at 40 CFR 60.24a(f)(1) provides that a state must evaluate these systems of emission reduction *to the extent necessary* to determine the standard of performance that is as close as reasonably possible to the presumptive standard of performance under these emission guidelines. It will most likely not be necessary for a state to consider all of the systems that the EPA identified for a given affected EGU. For example, if the state has already determined it is not

[930] See 88 FR 33384 (May 23, 2023).

reasonably possible for an affected EGU to implement one of these control strategies, at any stringency, as part of its demonstration under 40 CFR 60.24a(e) that a less stringent standard of performance is warranted, the state does not need to evaluate that system again. Similarly, if a state starts by evaluating the system that achieves the greatest emission reductions and determines the affected EGU can implement that system, it is most likely not necessary for the state to consider the other systems on the list in order to determine that the resulting standard of performance is no less stringent than necessary. The Agency anticipates that states will leverage the information the EPA has provided regarding systems of emission reduction in these emission guidelines, as well as the wealth of other technical, cost, and related information on various control systems in the record for this final action, in conducting their evaluations under 40 CFR 60.24a(f). In many cases, it will be possible for states to use information the EPA has provided as a starting point and particularize it for the circumstances of an individual affected EGU.[931]

For systems of emission reduction that have a range of potential stringencies, states should start by evaluating the most stringent iteration that is potentially feasible for the particular affected EGU. If that level of stringency is not reasonable, the state should also evaluate other stringencies as may be needed to determine the standard of performance that is no less stringent than the applicable degree of emission limitation in these emission guidelines than necessary.

In evaluating the systems of emission reduction identified in these emissions guidelines, states must also consider the factors and evaluation metrics that the EPA considered in assessing those systems, including technical feasibility, the amount of emission reductions, any non-air quality health and environmental impacts, and energy requirements. 40 CFR 60.24a(f)(1). They may also consider, in evaluating systems of emission reduction, other factors specific to the facility that constitute a fundamental difference between the information the EPA considered and the circumstances of the particular affected EGU and that were the basis of invoking RULOF for that particular EGU. For example, if a state determined that it is physically impossible or technically infeasible and/or unreasonably costly for a long-term coal-fired affected EGU to construct a CO_2 pipeline because the EGU is located on a remote island, the state could consider that information in evaluating additional systems of emission reduction, as well.

The general implementing regulations at 40 CFR 60.24a(f)(2) provide that any less stringent standards of performance that a state applies pursuant to RULOF must be in the form required by the applicable emission guideline. The presumptive standards of performance the EPA is providing in these emission guidelines are rate-based emission limitations. In order to ensure that a source-specific standard of performance is no less stringent than the EPA's presumptive standard than necessary, the source-specific standard pursuant to RULOF must be determined and expressed in the form of a rate-based emission limitation. That is, the systems of emission reduction that states evaluate pursuant to 40 CFR 60.24a(f)(1) must be systems for reducing a source's emission rate and the state must apply a standard of performance expressed as an emission rate, in lb CO_2/MWh,[932] that is no less stringent than necessary. As discussed in section X.D.1.b of this preamble, the EPA is not providing that affected EGUs with standards of performance pursuant to consideration of RULOF can use mass-based or rate-based compliance flexibilities under these emission guidelines.

The general implementing regulations also provide that any compliance schedule extending more than twenty months past the state plan submission deadline must include legally enforceable increments of progress. 40 CFR 60.24a(d). Due to the timelines the EPA is finalizing under these emission guidelines, any affected EGU with compliance obligations pursuant to consideration of RULOF will have a compliance schedule that triggers the need for increments of progress in state plans. Because compliance obligations pursuant to RULOF are, by their nature, source-specific, the EPA is not providing particular increments of progress for sources for which RULOF has been invoked in these emission guidelines. Therefore, states must provide increments of progress for RULOF sources in their state plans that comply with the generally applicable requirements in 40 CFR 60.24a(d) and 40 CFR 60.21a(h).

Additionally, 40 CFR 60.24a(h) requires that a less stringent standard of performance must meet all other applicable requirements of both the general implementing regulations and these emission guidelines.

i. Determining a Less-Stringent Standard of Performance for Long-Term Coal Fired Steam Generating EGUs

The EPA identified four potential systems of emission reduction for long-term coal-fired steam generating EGUs: CCS with 90 percent CO_2 capture, CCS with partial CO_2 capture/lower capture rates, natural gas co-firing, and HRI. If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular affected coal-fired EGU in the long-term subcategory can install and operate CCS but cannot reasonably achieve an 88.4 percent degree of emission limitation using CCS or any other systems of emission reduction, under the process laid out in 60.24a(f)(1) the state would proceed to evaluate CCS with lower rates of CO_2 capture. The state would identify the most stringent degree of emission limitation the affected EGU can reasonably achieve using CCS and that degree of emission limitation would become the basis for the source's less stringent standard of performance.[933]

If a state has demonstrated, pursuant to 40 CFR 60.24a(e), that a particular affected coal-fired EGU cannot reasonably install and operate CCS as a control strategy and cannot otherwise achieve the presumptive standard of performance, the state would proceed to evaluate natural gas co-firing and HRI as potential control strategies. Because 40 CFR 60.24a(f)(1) requires that a standard of performance be no less stringent than necessary to address the fundamental differences that were the basis for invoking RULOF, states would start by evaluating natural gas co-firing at 40 percent. If the affected EGU cannot

[931] See, *e.g.,* sections VII.C.1–4 of this preamble, the final TSD, *GHG Mitigation Measures for Steam Generation* Units, the CO_2 Capture Project Schedule and Operations Memo, Documentation for the Lateral Cost Estimation, Transport and Storage Timeline Summary, and the Heat Rate Improvement Method Costs and Limitations Memo.

[932] The presumptive standards of performance for coal-fired steam-generating affected EGUs and base load and intermediate load natural gas- and oil-fired steam generating affected EGUs are in units of lb CO_2/MWh; thus, any standards of performance pursuant to consideration of RULOF must be determined in these units, as well. The presumptive standard of performance for low-load natural gas-fired and oil-fired affected EGUs are in units of lb CO_2/MMBtu. While the EPA does not expect that states will use the RULOF provisions to provide less stringent standards of performance for these sources because their BSER is based on uniform fuels, should a state do so, the standard of performance would be determined in units of lb CO_2/MMBtu.

[933] 40 CFR 60.24a(f) requires that a standard of performance pursuant to consideration of RULOF be no less stringent than necessary to address the fundamental difference identified under 40 CFR 60.24a(e). If a particular affected EGU can install and operate CCS but only at such a low CO_2 capture rate that it could reasonably achieve greater stringency based on natural gas co-firing, the state would apply a standard of performance based on natural gas co-firing.

reasonably co-fire at 40 percent, the state would proceed to evaluate lower levels of natural gas co-firing unless it has demonstrated that the EGU cannot reasonably co-fire any amount of natural gas. If that is the case, the state would then evaluate HRI as a control strategy. The EPA notes that states may also consider additional systems of emission reduction that may be available and reasonable for particular EGUs.

ii. Determining a Less-Stringent Standard of Performance for Medium-Term Coal Fired Steam Generating EGUs

The EPA identified three potential systems of emission reduction for affected coal-fired steam generating EGUs in the medium-term subcategory: CCS, natural gas co-firing, and HRI. The EPA explained in section VII.D.2.b.i of this preamble that the cost effectiveness of CCS is less favorable for medium-term steam generating EGUs based on the short periods they have to amortize capital costs and utilize the IRC section 45Q tax credit. The EPA therefore believes that it would be reasonable for states determining a less stringent standard of performance for an affected EGU in the medium-term subcategory to forgo evaluating CCS as a potential control strategy. States would therefore start by evaluating lower levels of natural gas co-firing, unless a state has demonstrated pursuant to 40 CFR 60.24a(e) that the particular EGU cannot reasonably install and implement natural gas co-firing as a system of emission reduction. If that is the case, the state would evaluate HRI as the basis for a standard of performance that is no less stringent than necessary.

The EPA expects that any coal-fired steam generating EGU to which a less stringent standard of performance is being applied will be able to reasonably implement some system of emission reduction; at a minimum, the Agency believes that all sources could institute approaches to maintain their historical heat rates.

iii. Determining a Longer Compliance Schedule

Pursuant to 40 CFR 60.24a(f)(1), a longer compliance schedule pursuant to consideration of RULOF must be no longer than necessary to address the fundamental difference identified pursuant to 40 CFR 60.24a(e). For states that are providing extensions to the schedules in the EPA's emission guidelines, implementation of this requirement is straightforward. States should provide any information and analyses discussed in other sections of this preamble as relevant to justifying the need for, and length of, any compliance schedule extensions under the RULOF provisions. For states that are applying less stringent standards of performance that are based on a system of emission reduction other than the BSER for that subcategory, states should apply a compliance schedule consistent with installation and implementation of that system that is as expeditious as practicable.[934]

Comment: One commenter asserted that the 2023 proposed rule indicated that states invoking RULOF would be required to evaluate certain controls, in a certain order, as appropriate for subcategories of affected EGUs. The commenter stated that the EPA must defer to states' consideration of other systems of emission reduction that the EPA has determined are not the BSER, including the manner in which the states choose to consider those systems.

Response: The EPA is not finalizing the proposed requirements in these emission guidelines that would have specified the systems of emission reduction that states must consider when invoking RULOF and the order in which they consider them. The EPA is instead providing that states' analyses and determinations of less stringent standards of performance pursuant to RULOF must be conducted in accordance with the generally applicable requirements of the part 60, subpart Ba implementing regulations; specifically, 40 CFR 60.24a(f). While the requirements under this regulation for determining less stringent standards of performance pursuant to RULOF are similar to the requirements proposed under these emission guidelines, they are also, as described above, more flexible because they provide (1) that states must consider other systems of emission reduction *to the extent necessary* to determine the standard of performance that is no less stringent than the EPA's degree of emission limitation than necessary, and (2) that states may consider other systems of emission reduction, in addition to those the EPA identified in the applicable emission guidelines.

c. Contingency Requirements

Per the general implementing regulations at 40 CFR 60.24a(g), if a state invokes RULOF based on an operating condition within the control of an affected EGU, such as remaining useful life or a specific level of utilization, the state plan must include such operating condition or conditions as an enforceable requirement. The state plan must also include provisions that provide for the implementation and enforcement of the operating conditions, including requirements for monitoring, reporting, and recordkeeping. The EPA notes that there may be circumstances in which an affected EGU's circumstances change after a state has submitted its state plan; states may always submit plan revisions if needed to alter an enforceable requirement therein.

Comment: One commenter stated that if a state does not accept the presumptive standards of performance for a facility, it must establish federally enforceable retirement dates and operating conditions for that facility. The commenter asserted that the CAA does not authorize the EPA to constrain states' discretion by requiring them to impose such restrictions as the price for exercising the RULOF authority granted by Congress. The commenter suggested that the EPA eliminate the requirement to include enforceable retirement dates and restrictions on operations in conjunction with a RULOF determination and stated that states should retain discretion to decide whether and when, based on RULOF, it is necessary to impose such restrictions on sources.

Response: The EPA clarifies that states are in no way required to impose enforceable retirement dates or operating restrictions on affected EGUs under these emission guidelines. It is entirely within a state's control to decide whether such a requirement is appropriate for a source. If a state determines that it is, in fact, appropriate to codify an affected EGU's intention to cease operating or limit its operations as an enforceable requirement, the state may use such considerations as the basis for applying, as warranted, a less stringent standard of performance to that source. This allowance is provided under the subpart Ba general implementing regulations, 40 CFR 60.24a(g).

d. More Stringent Standards of Performance in State Plans

States always have the authority and ability to include more stringent standards of performance and faster compliance schedules as federally enforceable requirements in their state plans. They do not need to use the RULOF provisions to do so. See 40 CFR 60.24a(i).

e. Interaction of RULOF and Other State Plan Flexibilities and Mechanisms

The EPA discusses the ability of affected EGUs with standards of performance determined pursuant to 40 CFR 60.24a(f) to use compliance

[934] See 40 CFR 60.24a(c).

flexibilities under these emission guidelines in section X.D of this preamble.

i. Use of RULOF To Address Reliability

The EPA, in determining the degree of emission limitation achievable through application of the BSER for coal-fired steam generating EGUs, analyzed potential impacts of the BSERs on resource adequacy in addition to considering multiple studies on how reliability could be impacted by these emission guidelines. In doing so, the Agency considered potential large-scale (regional and national) and long-term impacts on the reliability of the electricity system under CAA section 111(a)(1)'s ''energy requirements'' factor. In evaluating CCS as a control strategy for long-term coal-fired steam generating EGUs, the Agency determined that CCS as the BSER would have limited and non-adverse impacts on the long-term structure of the power sector or on reliability of the power sector. See section VII.C.1.a.iii.(F) and final TSD, *Resource Adequacy Analysis.* Additionally, the EPA has made several adjustments to the final emission guidelines relative to proposal that should have the effect of alleviating any reliability concerns, including changing the scope of units covered by these actions and removing certain subcategories, including one that would have included an annual capacity factor limitation. See section XII.F of this preamble for further discussion.

While the EPA has determined that the structure and requirements of these emission guidelines will not negatively impact large-scale and long-term reliability, it also acknowledges the more locationally specific, source-by-source decisions that go into maintaining grid reliability. For example, there may be circumstances in which a balancing authority may need to have a particular unit available at a certain time in order to ensure reliability of the larger system. As noted above, the structure and various mechanisms of these emission guidelines allow states and reliability authorities to plan for compliance in a manner that preserves grid operators' abilities to maintain electric reliability. Specifically, coal-fired EGUs that are planning to cease operation do not have control requirements under these emission guidelines, the removal of the imminent-term and near-term subcategories means that states and reliability authorities have greater flexibility in the earlier years of implementation, and the EPA is providing two dedicated reliability mechanisms. Given these adjustments, the Agency believes there will remain very few, if any, circumstances in which states will need to provide particularized compliance obligations for an affected EGU based on a need to address reliability. However, there may be isolated instances in which a particular affected EGU cannot reasonably comply with the applicable requirements due to a source-specific reliability issue. Such unit-specific reliability considerations may constitute an ''[o]ther circumstance[] specific to the facility'' that makes it unreasonable for a particular EGU to achieve the degree of emission limitation or compliance schedule the EPA has provided in these emission guidelines. 40 CFR 60.24a(e)(1)(iii). The EPA is therefore confirming that states may use the RULOF provisions in 40 CFR 60.24a to apply a less stringent standard of performance or longer compliance schedule to a particular affected EGU based on reliability considerations. The EPA emphasizes that the RULOF provisions should not be used to provide a less stringent standard of performance if the applicable degree of emission limitation for an affected EGU is reasonably achievable. To do so would be inconsistent with CAA sections 111(d) and 111(a)(1). Thus, to the extent states and affected EGUs find it necessary to use RULOF to particularize these emission guidelines' requirements for a specific unit based on reliability concerns, such adjustments should take the form of longer compliance schedules.

In order to meet the threshold for applying a less stringent standard of performance or longer compliance schedule based on unit-specific reliability considerations under 40 CFR 60.24a(e), a state must demonstrate a fundamental difference between the information the EPA considered on reliability and the circumstances of the specific unit. This demonstration would be made by showing that requiring a particular affected EGU to comply with its presumptive standard of performance under the specified compliance timeframe would compromise reliability, *e.g.,* by necessitating that the affected EGU be taken offline for a specific period of time during which a resource adequacy shortfall with adverse impacts would result. In order to make this demonstration, states must provide an analysis of the reliability risk if the particular affected EGU were required to comply with its applicable presumptive standard of performance by the compliance date, clearly demonstrating that the EGU is reliability critical such that requiring it to comply would trigger non-compliance with at least one of the mandatory reliability standards approved by FERC or cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region. Specifically, this requires a clear demonstration that each unit for which use of RULOF is being considered would be needed to maintain the targeted level of resource adequacy.[935] The analysis must also include a projection of the period of time for which the particular affected EGU is expected to be reliability critical. States must also provide an analysis by the relevant reliability Planning Authority [936] that corroborates the asserted reliability risk and confirms that one or both of the circumstances would result from requiring the particular affected EGU to comply with its applicable requirements, and also confirms the period of time for which the EGU is projected to be reliability critical. The state plan must also include a certification from the Planning Authority that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested.

To substantiate a reliability risk that stems from resource adequacy in particular, the analyses must also demonstrate that the specific affected EGU has been designated by the relevant Planning Authority as needed for resource adequacy and thus reliability, and that requiring that affected EGU to comply with the requirements in these emission guidelines would interfere with its ability to serve this function as intended by the Planning Authority. However, the EPA reiterates that the structure of the subcategories for coal-fired steam generating affected EGUs in these final emission guidelines differs from the proposal in ways that should provide states and affected EGUs wider latitude to make the operational decisions needed to ensure resource adequacy. Thus, again, the Agency expects that the circumstances in which states need to rely on consideration of RULOF to

[935] See, *e.g.,* the North American Electric Reliability Corporation's ''Probabilistic Assessment: Technical Guideline Document,'' August 2016. *https://www.nerc.com/comm/RSTC/PAWG/proba_technical_guideline_document_08082014.pdf.*

[936] The North American Electric Reliability Corporation (NERC)'s currently enforceable definition of ''Planning Authority'' is, ''[t]he responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems.'' Glossary of Terms Used in NERC Reliability Standards, Updated April 1, 2024. *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

particularize an affected EGU's compliance obligation will be rare.

The EPA will review these analyses and documentation as part of its evaluation of standards of performance and compliance schedules that states apply based on consideration of reliability under the RULOF provisions.

As described in sections X.C.1.d and XII.F.3.b of this preamble, the EPA is providing two flexible mechanisms that states may incorporate in their plans that, if utilized, would provide a temporary delay of affected EGU's compliance obligations if there is a demonstrated reliability need.[937] The EPA anticipates that states discovering, after a state plan has been submitted and approved, that a particular affected EGU needs additional time to meet its compliance obligation as a result of a reliability or resource adequacy issue will avail themselves of these flexibilities. If a state anticipates that the reliability or resource adequacy issue will persist beyond the 1-year extension provided by these flexible mechanisms, the EPA expects that states will also initiate a state plan revision. In such a state plan revision, the state must make the demonstration and provides the analysis described above in order to use to adjust an affected EGU's compliance obligations to address the reliability or resource adequacy issue at that time.

The EPA intends to continue engagement on the topic of electric system reliability, resource adequacy, and linkages to various EPA regulatory efforts to ensure proper communication with key stakeholders and Federal counterparts including DOE and FERC. Additionally, the Agency intends to coordinate with its Federal partners with expertise in reliability when evaluating RULOF demonstrations that invoke this consideration. There are also opportunities to potentially provide information and technical support on implementation of these emission guidelines and critical reliability considerations that will benefit states, affected sources, system planners, and reliability authorities. Specifically, the DOE–EPA MOU on Electric System Reliability provides a framework for ongoing engagement, and the EPA intends to work with DOE to ensure that reliability stakeholders have additional and ongoing opportunities to engage EPA on this important topic.

Comment: The EPA received multiple comments on the use of the RULOF provisions to address reliability. Several commenters emphasized that states need the ability to adjust affected EGUs' compliance obligations for reasons linked to reliability. They elaborated that an independent system operator/regional transmission organization determination that an affected EGU is needed for reliability would be anchored in a RULOF analysis that considers forces that may drive the unit's premature retirement. Some commenters indicated that use of RULOF to address such units would allow those units to continue to operate for the required period of time, applying routine methods of operation, to address grid reliability. They similarly noted that sources that have foreseeable retirement glidepaths but are key resources could be offered a BSER that promotes the EPA's carbon reduction goals but falls outside of the Agency's one-size-fits-all BSER approach.

Another commenter suggested that states should be able to modify a subcategory in their plans to address a reliability issue, and provided the example of allowing a unit that is planning to retire at the end of 2032 but that is needed for reliability purposes at greater than 20 percent capacity factor to subcategorize as an imminent-term unit despite operating past the end date for the imminent-term subcategory. The commenter suggested that such a modification could be justified under both the remaining useful life consideration and the energy requirements consideration of RULOF. Other commenters similarly requested that the EPA clarify that the RULOF provisions can be used to accommodate the changes in the power sector, *e.g.,* the build-out of transmission and distribution infrastructure, that are ongoing and that may impact the anticipated operating horizons of some affected EGUs.

Response: As explained above, the EPA has analyzed the potential impacts of these emission guidelines and determined that they would have limited and non-adverse impacts on large-scale and long-term reliability and resource adequacy. However, the EPA acknowledges that there may be reliability-related considerations that apply at the level of a particular EGU that the Agency could not have known or foreseen and did not consider in its broader assessment. As described above, states may use the RULOF provision to address reliability or resource adequacy if they demonstrate, based on the analysis and consultation with planning authorities described in this section of this preamble, that there is a fundamental difference between the information the EPA considered in these emission guidelines and the circumstances and information relevant to a particular affected EGU that makes it unreasonable for that EGU to comply with its presumptive standard of performance by the applicable compliance date.

The EPA stresses that a generic or unsubstantiated reliability or resource adequacy concern is not sufficient to substantiate a fundamental difference or unreasonableness of complying with applicable requirements. Simply asserting that grid reliability or resource adequacy is a concern for a state and thus an affected EGU needs a less stringent standard of performance or longer compliance schedule would not be sufficient. Rather, a state would have to demonstrate, via the certification and analysis described above, that the relevant planning authority has designated a particular affected EGU as reliability or resource adequacy critical and that requiring that EGU to comply with its standard of performance by the applicable compliance date would interfere with the maintenance of reliability or resource adequacy as intended by that planning authority.

A standard of performance or compliance schedule that has been particularized for an affected EGU based on consideration of reliability or resource adequacy must, pursuant to 40 CFR 60.24a(f), be no less stringent than necessary to address the fundamental difference identified pursuant to 40 CFR 60.24a(e), which in this case would be unit-specific grid reliability or resource adequacy needs. A less stringent standard of performance does not necessarily correspond to a standard of performance based on routine methods of operation and maintenance.

The EPA notes that states do not need to use the RULOF provisions to justify the date on which a particular affected EGU plans to cease operation. RULOF only comes into play if there is a fundamental difference between the information the EPA considered and the information specific to an affected EGU with a shorter remaining useful life that makes achieving the EPA's presumptive standard of performance unreasonable,, *e.g.,* the amortized cost of control. If a state elects to rely on an affected EGU's operating conditions, such as a plan to permanently cease operation, as the basis for applying a less stringent standard of performance, those conditions must be included as an

[937] The mechanism described in section X.C.1.d of this preamble is not restricted to circumstances in which a state needs to provide an affected EGU with additional time to comply with its standard of performance specifically for reliability or resource adequacy, but it can be used for this purpose. The reliability mechanism described in section XII.F.3.b is specific to reliability and can be used to extend the date by which a source plans to cease operating by up to 1 year.

enforceable commitment in the state plan.

As explained elsewhere in this section of the preamble, the effect of RULOF is not to modify subcategories under these emission guidelines but rather to particularize the compliance obligations of an affected EGU within a given subcategory. The EPA also notes that it is not finalizing the proposed imminent-term or near-term subcategories for affected coal-fired steam generating EGUs.

ii. Use of RULOF With Compliance Date Extension Mechanism

As discussed in section X.C.1.d of the preamble to this final rule, the EPA is allowing states to include in their plans a mechanism to provide a compliance deadline extension of up to 1 year for certain affected EGUs. This mechanism would be available for affected EGUs with standards of performance that require add-on control technologies and that demonstrate the extension is needed for installation of controls due to circumstances outside the control of the affected EGU. In the event the state and affected EGU believe that 1 year will not be sufficient to remedy those circumstances, *i.e.,* that the affected EGU will not be able to comply with its standard of performance even with a 1-year extension, the state may also start the process of revising its plan to apply a longer compliance schedule based on consideration of RULOF. In order to demonstrate that there is a fundamental difference between the circumstances of the affected EGU and the information the EPA considered in determining the compliance schedule in the emission guidelines, the state should provide documentation to justify why it is unreasonable for the affected EGU to meet that compliance schedule, even with an additional year (providing that the state has allowed for a 1-year extension), based on one or more of the considerations in 40 CFR 60.24a(e)(1). This documentation should demonstrate that the need to provide a longer compliance schedule was due to circumstances outside the affected EGU's control and that the affected EGU has met all relevant increments of progress and other obligations in a timely manner up to the point at which the delay occurred. That is, the state must demonstrate that the need to invoke RULOF and to provide a longer compliance schedule was not caused by self-created circumstances. As discussed in sections X.C.1.d and X.C.2.a of this preamble, documentation such as permits obtained and/or contracts entered into for the installation of control technology, receipts, invoices, and correspondence with vendors and regulators is helpful evidence for demonstrating that states and affected EGUs have been making progress towards compliance and that the need for a longer compliance schedule is due to circumstances outside the affected EGU's control.

In establishing a longer compliance schedule pursuant to 40 CFR 60.24a(f)(1), a state must demonstrate that the revised schedule is no longer than necessary to accommodate circumstances that have resulted in the delay.

3. Increments of Progress for Medium-Term and Long-Term Coal-Fired Steam Generating EGUs

The EPA's longstanding CAA section 111 implementing regulations provide that state plans must include legally enforceable Increments of Progress (IoPs) toward achieving compliance for each designated facility when the compliance schedule extends more than a specified length of time from the state plan submission date. Under the subpart Ba revisions finalized in November 2023, IoPs are required when the final compliance deadline (*i.e.,* the date on which affected EGUs must start monitoring and reporting emissions data and other information for purposes of demonstrating compliance with standards of performance) is more than 20 months after the plan submittal deadline. These emission guidelines for steam EGUs finalize a 24-month state plan submission deadline and compliance dates of January 1, 2032 (for long-term coal-fired EGUs), and January 1, 2030 (for all other steam generating EGUs), exceeding subpart Ba's 20-month threshold. Under these emission guidelines, in particular, the lengthy planning and construction processes associated with the CCS and natural gas co-firing BSERs make IoPs an appropriate mechanism to assure steady progress toward compliance and to provide transparency on that progress.

The EPA received support for the proposed approach to IoPs from many commenters; others, however, offered adverse perspectives. Supportive commenters generally emphasized the need for clear, transparent, and enforceable implementation checkpoints between state plan submittal and the compliance dates given the lengthy timelines affected EGUs are being afforded to achieve their standards of performance. These comments were broadly consistent with the proposed rationale for the IoPs. Adverse comments are addressed at the end of this subsection of the preamble.

The EPA is finalizing IoPs for affected EGUs based on BSERs that involve installation of emissions controls: long-term coal-fired EGUs and medium-term coal-fired EGUs. Units complying through the BSER specified for each subcategory, either CCS for the long-term subcategory or natural gas co-firing for the medium-term subcategory, must use IoPs tailored to those BSERs. Units complying through a different control technology must adopt increments that correspond to each of the steps in 40 CFR 60.21a(h). As specified in the proposal, each increment must be assigned a calendar date deadline, but states have discretion to set those dates based on the unique circumstances of each unit. The EPA is also finalizing its proposal to exempt the natural gas- and oil-fired EGU subcategories from IoP requirements. These subcategories have BSERs of routine operation and maintenance, which does not require the installation of significant new emission controls or operational changes.

The EPA is finalizing the proposed approach allowing states to choose the calendar dates for all IoPs for long- and medium-term coal-fired EGUs, subject to two constraints. The IoP corresponding to 40 CFR 60.21a(h)(1), submittal of a final control plan to the air pollution control agency, must be assigned the earliest calendar date deadline among the increments, and the IoP corresponding to 40 CFR 60.21a(h)(5), final compliance, must be assigned a date aligned with the compliance date for each subcategory, either January 1, 2032, for the long-term subcategory or January 1, 2030, for the medium-term subcategory. The EPA believes that this approach will provide states and EGUs with flexibility to account for idiosyncrasies in planning processes, tailor compliance timelines to individual facilities, allow simultaneous work toward separate increments, and ensure full performance by the compliance date.

For coal-fired EGUs assigned to the long-term and medium-term subcategories and that adopt the corresponding BSER (CCS or natural gas co-firing, respectively) as their compliance strategy, the EPA is finalizing BSER-specific IoPs that correspond to the steps in 40 CFR 60.21a(h). Some increments have been adjusted to more closely align with planning, engineering, and construction steps anticipated for affected EGUs that will be complying with standards of performance with natural gas co-firing or CCS, in particular; however, these technology-specific increments retain the basic structure and substance of the

increments in the general implementing regulations under subpart Ba. In addition, consistent with 40 CFR 60.24a(d), the EPA is finalizing similar additional increments of progress for the long-term and medium-term coal-fired subcategories that are specific to pipeline construction in order to ensure timely progress on the planning, permitting, and construction activities related to pipelines that may be required to enable full compliance with the applicable standard of performance. The EPA is also finalizing an additional increment of progress related to the identification of an appropriate sequestration site for the long-term coal-fired subcategory. Finally, the EPA is finalizing a requirement that state plans must require affected EGUs with increments of progress to post the activities or actions that constitute the increments, the schedule required in the state plan for achieving them, and, within 30 business days, any documentation necessary to demonstrate that they have been achieved to the Carbon Pollution Standards for EGUs website, as discussed in section X.E.1.b.ii of this preamble, in a timely manner.

For coal-fired steam generating units in the long-term subcategory adopting CCS as their compliance approach, the EPA is finalizing the following seven IoPs as enforceable elements required to be included in a state plan: (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan and must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or FEED study, the anticipated timeline to achieve full compliance, and the benchmarks anticipated along the way. (2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded. (3) Initiation of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CO_2 capture on an annual basis. (4) Completion of onsite construction or installation of emission control equipment or process change required to achieve 90 percent CO_2 capture on an annual basis. (5) Demonstration that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process(es), a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities. (6) Submittal of a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities. (7) Final compliance with the standard of performance. States must assign calendar deadlines for each increment consistent with the following requirements: the first increment, submission of a final control plan, must be assigned the earliest calendar date among the increments; the seventh increment, final compliance must be set for January 1, 2032.

For coal-fired steam generating units in the long-term subcategory adopting a compliance approach that differs from CCS, the EPA is finalizing the requirement that states adopt IoPs for each affected EGU that are consistent with the IoPs at 40 CFR 60.21a(h). As with long-term units adopting CCS as their compliance strategy, states must assign calendar deadlines for each increment consistent with the following requirements: the first increment, corresponding to 40 CFR 60.21a(h)(1), must be assigned the earliest calendar date among the increments; the final increment, corresponding to 40 CFR 60.21a(h)(5), must be set for January 1, 2032.

For coal-fired steam generating units in the medium-term subcategory adopting natural gas co-firing as their compliance approach, the EPA is finalizing the following six IoPs as enforceable elements required to be included in a state plan: (1) Submission of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration in the state plan and must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks anticipated along the way. (2) Awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish such modifications. Affected EGUs can demonstrate compliance with this increment by submitting sufficient evidence that the appropriate contracts have been awarded. (3) Initiation of onsite construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis. (4) Completion of onsite construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis. (5) Demonstration that all permitting actions related to pipeline construction have commenced by a date specified in the state plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting application process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permit applications is complete with respect to the authorizations required to operate the facility at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities. (6) Final compliance with the standard of performance. States must also assign calendar deadlines for each increment consistent with the following requirements: the first increment, submission of a final control plan, must be assigned the earliest calendar date among the increments; the sixth increment, final compliance, must be set for January 1, 2030.

For coal-fired steam generating units in the medium-term subcategory adopting a compliance approach that differs from natural gas co-firing, the EPA is finalizing the requirement that states adopt IoPs for each affected EGU that are consistent with the increments in 40 CFR 60.21a(h).

As with medium-term units adopting natural gas co-firing as their compliance strategy, states must assign calendar deadlines for each increment consistent with the following requirements: the first increment, corresponding to 40 CFR 60.21a(h)(1), must be assigned the earliest calendar date among the increments; the final increment, corresponding to 40 CFR 60.21a(h)(5), must be set for January 1, 2030.

The EPA notes that if an affected EGU receives approval for a compliance date extension, the date for at least one, if not several, IoPs must be adjusted to align with the revised compliance date. The new dates for the relevant IoPs must be specified in the application for the extension. The EPA notes that the last increment—final compliance—should be no later than 1 year after the original compliance date, pursuant to the requirements described in section X.C.1.d.

Comment: The EPA received comments that the proposed IoPs are too restrictive and may limit certain implementation flexibilities, namely that the burden to adjust IoPs after state plan submittal will limit sources' ability to switch subcategories or adjust implementation timelines due to unforeseen circumstances.

Response: The EPA has considered these comments and notes that the final rule includes planning flexibilities to address these situations. The first of these flexibilities is embedded in the subpart Ba regulations governing optional state plan revisions. Plan revisions, including revisions to subcategory assignments and any corresponding IoPs, may be used at a state's discretion to account for changes in planned compliance approaches. 40 CFR 60.28a. Such revisions can also include RULOF-based adjustments to approved standards of performance as well as the timelines to meet those standards, including the IoPs. Further, as mentioned above, the compliance date extension mechanism described in section X.C.1.d allows for modification of the IoPs to align with an approved compliance date extension. In addition, the subcategory structure of these final emission guidelines differs from that at proposal such that it is less likely that affected coal-fired EGUs will switch subcategories. In the event that an affected EGU does switch between the long-term and medium-term subcategories, the state plan revision process is the most appropriate mechanism because a different control strategy may be appropriate. Based on this consideration and the availability of planning flexibilities to account for changes in compliance plans and changed circumstances, the EPA is finalizing the approach to IoPs as proposed.

Comment: Some commenters raised concerns related to length of time between the state plan submittal deadline and the final compliance dates, namely that some IoPs will take place too far into the future to be reliably assigned calendar date deadlines.

Response: As noted above, the EPA has concluded that length of time between the state plan submittal deadline and the compliance deadlines for units in the medium-term and long-term subcategories as well as the anticipated complexity for units to comply with the final standards of performance necessitate the use of discrete interim checkpoints prior to final compliance, formally established as increments of progress, to ensure timely and transparent progress toward each unit's compliance obligation. It would be inconsistent to determine that the same factors necessitating the increments—the length of time between the state plan submittal deadline and the compliance obligation as well as the complex nature of the implementation process—also eliminate the IoPs' core accountability function by prohibiting the assignment of calendar date deadlines. Finally, as described above, the final emission guidelines also allow states and affected EGUs significant flexibility to determine when each increment applies.

Comment: Some commenters raised concerns that the IoPs could limit affected EGUs from selecting compliance approaches that differ from the BSER technology associated with each subcategory, namely averaging and trading.

Response: Under the approach finalized in this rule, units assigned to the long-term and medium-term subcategories that do not adopt the associated BSER as part of their compliance strategy must establish date-specified IoPs consistent with the subpart Ba IoPs codified at 40 CFR 60.21a(h). That is, states will particularize the generic IoPs in subpart Ba as appropriate for affected EGUs that comply with their standards of performance using control technologies other than CCS (for long-term units) or natural gas co-firing (for medium-term units). The EPA discusses considerations relevant to averaging and trading in section X.D of this preamble.

4. Reporting Obligations and Milestones for Affected EGUs That Plan to Permanently Cease Operations

The EPA proposed legally enforceable reporting obligations and milestones for affected EGUs demonstrating that they plan to cease operations and use that voluntary commitment for eligibility for the imminent-term, near-term, or medium-term subcategory. No reporting obligations and milestones were proposed for affected EGUs within the long-term subcategory since a voluntary commitment to cease operations was not part of the subcategory's applicability criteria. The proposed rationale for the milestone requirements recognized that the proposed subcategories were based on the operating horizons of units within each subcategory, and that there were numerous steps that EGUs in these subcategories need to take in order to effectuate their commitments to cease operations. The proposed reporting obligations and milestones were intended to provide transparency and assurance that affected EGUs could complete the steps necessary to qualify for a subcategory with a less stringent standard of performance.[938]

Of the proposed subcategories for which the reporting obligations and milestones were proposed to apply, the EPA's final emission guidelines retain only the medium-term coal-fired subcategory. Though the EPA is finalizing only one subcategory with an associated operational time horizon, the Agency has determined that the original rationale for the milestones is still valid. That is, the BSER determination for EGUs assigned to the medium-term subcategory is contingent on sources within this subcategory having limited operating horizons relative to affected EGUs in the long-term subcategory, and the integrity of the subcategory approach and the environmental integrity of these emission guidelines depend on sources behaving consistent with the operating horizon they have represented in the state plan. The steps required for EGUs to cease operations are numerous and vary across jurisdictions; giving states, the EPA, and other stakeholders insight into these steps and affected EGUs' progress along these steps provides assurance that they are on track to meeting their state plan requirements. The reporting obligations and milestones the EPA is finalizing under these emission guidelines are a reasonable approach to assuring transparency and timely compliance; they can also serve as an early indication that a state plan revision may be necessary if it becomes apparent that an affected EGU is not meeting its designated milestones. Further, the agency has determined that a similar rationale for requiring reporting obligations and milestones applies to

[938] 88 FR 33390 (May 23, 2023).

affected EGUs that invoke RULOF based on a unit's remaining useful life. States may apply a less stringent standard of performance to a particular affected EGU if its shorter remaining useful life results in a fundamental difference between the circumstances of that EGU and the information the EPA considered, and that difference makes it unreasonable for the EGU to achieve the presumptive standard of performance. However, if such a unit continues to operate past the date by which it previously committed to cease operating, the basis for the less stringent standard of performance is abrogated and the environmental integrity of the emission guidelines compromised. Therefore, as for affected EGUs in the medium-term subcategory, the reporting obligations and milestones are an essential component of assuring that affected EGUs that invoke RULOF based on a unit's remaining useful life are actually able to satisfy the condition of receiving the less stringent standard in the first instance.

The EPA is finalizing the following milestones and reporting requirements, explained in more detail below, for both affected EGUs assigned to the medium-term subcategory and affected EGUs that invoke RULOF based on a unit's remaining useful life. These sources must submit an Initial Milestone Report five years before the date by which it will permanently cease operations, annual Milestone Status Reports for each intervening year between the initial report and the date operations will cease, and a Final Milestone Status Report no later than six months from the date by which the affected EGU has committed to cease operating.

Commenters expressed a range of views regarding the proposed reporting obligations and milestones. Some were broadly supportive of the reporting milestones and the EPA's stated rationale to provide a mechanism to help ensure that affected EGUs progress steadily toward a commitment to cease operations when that commitment affects the stringency of their standard of performance. Summaries of and responses to additional comments on the reporting obligations and milestones are addressed at the end of this subsection.

The discussion below refers to reporting ''milestones.'' Owners/operators of sources take a number of process steps in preparing a unit to cease operating (*i.e.,* preparing it to deactivate). The EPA is requiring that states select certain of these steps to serve as milestones for the purpose of reporting where a source is in the process; the EPA is designating two milestones in particular and states will select additional steps for reporting milestones. The requirements being established under these emission guidelines do not require milestone steps to be taken at any particular time—they merely require reporting on when a source intends to reach each of its designated milestones and whether and when it has actually done so. The reporting obligations and milestone requirements count backward from the calendar date by which an affected EGU has committed to permanently cease operations, which must be included in the state plan, to monitor timely progress toward that date. Five years before any planned date to permanently cease operations or 60 days after state plan submission, whichever is later, the owner or operator of affected EGUs must submit an Initial Milestone Report to the applicable air pollution control agency that includes the following: (1) A summary of the process steps required for the affected EGU to permanently cease operation by the date included in the state plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. (2) A list of key milestones that will be used to assess whether each process step has been met, and calendar day deadlines for each milestone. These milestones must include at least the initial notice to the relevant reliability authority of an EGU's deactivation date and submittal of an official retirement filing with the EGU's reliability authority. (3) An analysis of how the process steps, milestones, and associated timelines included in the Initial Milestone Report compare to the timelines of similar EGUs within the state that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines. (4) Supporting regulatory documents, including correspondence and official filings with the relevant regional transmission organization (RTO), independent system operator (ISO), balancing authority, public utility commission (PUC), or other applicable authority; any deactivation-related reliability assessments conducted by the RTO or ISO; and any filings pertaining to the EGU with the United States Securities and Exchange Commission (SEC) or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which the plans for the EGU are mentioned; any integrated resource plans and PUC orders approving the EGU's deactivation; any reliability analyses developed by the RTO, ISO, or relevant reliability authority in response to the EGU's deactivation notification; any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and any notification to or from an RTO, ISO, or balancing authority altering the timing of deactivation for the EGU.

For each of the remaining years prior to the date by which an affected EGU has committed to permanently cease operations that is included in the state plan, it must submit an annual Milestone Status Report that addresses the following: (1) Progress toward meeting all milestones identified in the Initial Milestone Report; and (2) supporting regulatory documents and relevant SEC filings, including correspondence and official filings with the relevant regional transmission organization, balancing authority, public utility commission, or other applicable authority to demonstrate compliance with or progress toward all milestones.

The EPA is also finalizing a provision that affected EGUs with reporting milestones associated with commitments to permanently cease operations would be required to submit a Final Milestone Status Report no later than 6 months following its committed closure date. This report would document any actions that the unit has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

The EPA is finalizing a requirement that affected EGUs with reporting milestones for commitments to permanently cease operations must post their Initial Milestone Report, annual Milestone Status Reports, and Final Milestone Status Report, including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the Carbon Pollution Standards for EGUs website, as described in section X.E.1.b, within 30 business days of being filed. The EPA recognizes that applicable regulatory authorities, retirement processes, and retirement approval criteria will vary across states and affected EGUs. The proposed milestone reporting requirements are intended to establish a general framework flexible enough to account for significant differences across jurisdictions while assuring timely planning toward the dates by which affected EGUs permanently cease operations.

Comment: Some commentors questioned the need for the milestone reports by pointing to existing closure enforcement mechanisms within their jurisdictions.

Response: The existence of enforceable mechanisms in some jurisdictions does not obviate the need for the reporting milestones under these emission guidelines. First, the closure requirements, the nature of the enforcement mechanisms, and process requirements to cease operations will vary across different jurisdictions, and some jurisdictions may lack mechanisms entirely. The reporting milestones framework sets a uniform floor for reporting progress toward a commitment to cease operations, reducing differences in the quality and scope of information available to the EPA and public regarding closures. Second, the reporting milestones under these emission guidelines serve the additional purpose of transparency and allowing all stakeholders to have access to information related to affected EGUs' ongoing compliance.

Comment: Some commentors noted the unique EGU closure processes within their own jurisdictions and expressed concern as to whether the milestones requirements were too rigid to accommodate them.

Response: The reporting milestones are designed to create a flexible reporting framework that can accommodate differences in state closure processes. States can satisfy the required elements of the milestone reports by explaining how the process steps for plant closures within their jurisdiction work and establishing milestones corresponding to the process steps required within individual jurisdictions.

5. Testing and Monitoring Requirements

a. Emissions Monitoring and Reporting

The EPA proposed to require that state plans must include a requirement that affected EGUs monitor and report hourly CO_2 mass emissions emitted to the atmosphere, total heat input, and total gross electricity output, including electricity generation and, where applicable, useful thermal output converted to gross MWh, in accordance with the 40 CFR part 75 monitoring, reporting, and recordkeeping requirements. The EPA is finalizing a requirement that affected EGUs must use a 40 CFR part 75 certified monitoring methodology and report the hourly data on a quarterly basis, with each quarterly report due to the Administrator 30 days after the last day in the calendar quarter. The 40 CFR part 75 monitoring provisions require most coal-fired boilers to use a CO_2 continuous emissions monitoring system (CEMS), including both a CO_2 concentration monitor and a stack gas flow monitor. Some oil- and gas-fired boilers may have options to use alternative measurement methodologies (*e.g.,* fuel flow meters combined with fuel quality data).

The EPA received comments supporting and opposing the requirement to use 40 CFR part 75 monitoring, reporting, and recordkeeping requirements.

Comment: Commenters generally supported these requirements, noting that the majority of EGUs affected by this rule already monitor and submit emissions reports under 40 CFR part 75 under existing programs, including the Acid Rain Program and/or Regional Greenhouse Gas Initiative—a cooperative of several states formed to reduce CO_2 emissions from EGUs. In addition, EGUs that are not required to monitor and report under one of those programs may have 40 CFR part 75 certified monitoring systems in place for the MATS or CSAPR.

Response: The EPA agrees with these comments. Relying on the same monitors that are certified and quality assured in accordance with 40 CFR part 75 reduces implementation costs and ensures consistent emissions data across regulatory programs.

Comment: Some commenters focused on potential measurement bias of 40 CFR part 75 certified monitoring systems, with commenters split on whether the data are biased high or low.

Response: The EPA disagrees that the data reported under 40 CFR part 75 are biased significantly high or low. Each CO_2 CEMS must undergo regular quality assurance and quality control activities including periodic relative accuracy test audits (RATAs) where a monitoring system is compared to an independent monitoring system using EPA reference methods and NIST-traceable calibration gases. In a May 2022 study conducted by the EPA, the absolute value of the median difference between EGUs' monitoring systems and independent monitoring systems using EPA reference methods was found to be approximately 2 percent for CO_2 concentration monitors and stack gas flow monitors in the years 2017 through 2021.[939]

b. CCS-Specific Technology Monitoring and Reporting

Affected EGUs employing CCS must comply with relevant monitoring and reporting requirements specific to CCS. As described in the proposal, the CCS process is subject to monitoring and reporting requirements under the EPA's GHGRP (40 CFR part 98). The GHGRP requires reporting of facility-level GHG data and other relevant information from large sources and suppliers in the U.S. The ''suppliers of carbon dioxide'' source category of the GHGRP (GHGRP subpart PP) requires those affected facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground to report the mass of CO_2 captured and supplied. Facilities that inject a CO_2 stream underground for long-term containment in subsurface geologic formations report quantities of CO_2 sequestered under the ''geologic sequestration of carbon dioxide'' source category of the GHGRP (GHGRP subpart RR). In April 2024, to complement GHGRP subpart RR, the EPA finalized the ''geologic sequestration of carbon dioxide with enhanced oil recovery (EOR) using ISO 27916'' source category of the GHGRP (GHGRP subpart VV) to provide an alternative method of reporting geologic sequestration in association with EOR.[940] [941] [942]

As discussed in section VII.C.1.a.vii, the EPA is finalizing a requirement that any affected unit that employs CCS technology that captures enough CO_2 to meet the standard and injects the captured CO_2 underground must report under GHGRP subpart RR or GHGRP subpart VV. If the emitting EGU sends the captured CO_2 offsite, it must transfer the CO_2 to a facility subject to the GHGRP requirements, and the facility injecting the CO_2 underground must

[939] Zintgraff, Stacey. 2022. Monitoring Insights: Relative Accuracy in EPA CAMD's Power Sector Emissions Data. *www.epa.gov/system/files/documents/2022-05/Monitoring%20Insights-%20Relative%20Accuracy.pdf.*

[940] EPA. (2024). Rulemaking Notices for GHG Reporting. *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[941] International Standards Organization (ISO) standard designated as CSA Group (CSA)/American National Standards Institute (ANSI) ISO 27916:2019, *Carbon Dioxide Capture, Transportation and Geological Storage—Carbon Dioxide Storage Using Enhanced Oil Recovery (CO_2-EOR)* (referred to as ''CSA/ANSI ISO 27916:2019'').

[942] As described in 87 FR 36920 (June 21, 2022), both subpart RR and subpart VV (CSA/ANSI ISO 27916:2019) require an assessment and monitoring of potential leakage pathways; quantification of inputs, losses, and storage through a mass balance approach; and documentation of steps and approaches used to establish these quantities. Primary differences relate to the terms in their respective mass balance equations, how each defines leakage, and when facilities may discontinue reporting.

report under GHGRP subpart RR or GHGRP subpart VV. These emission guidelines do not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to the EPA's UIC program under the Safe Drinking Water Act.

The EPA also notes that compliance with the standard is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic sequestration site are not part of that calculation, though the EPA anticipates that the quantity of CO_2 sequestered will be substantially similar to the quantity captured. To verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, we are leveraging regulatory requirements under the GHGRP. The BSER is determined to be adequately demonstrated based solely on geologic sequestration that is not associated with EOR. However, EGUs also have the compliance option to send CO_2 to EOR facilities that report under GHGRP subpart RR or GHGRP subpart VV. We also emphasize that these emission guidelines do not involve regulation of downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2. The requirement that the emitting EGU transfer the captured CO_2 to an entity subject to the GHGRP requirements is thus exclusively an element of enforcement of the EGU standard. This will avoid duplicative monitoring, reporting, and verification requirements between this proposal and the GHGRP, while also ensuring that the facility injecting and sequestering the CO_2 (which may not necessarily be the EGU) maintains responsibility for these requirements. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of the final emission guidelines.

D. Compliance Flexibilities

In the finalized subpart Ba revisions, *Adoption and Submittal of State Plans for Designated Facilities: Implementing Regulations Under Clean Air Act Section 111(d),* the EPA explained that, under its interpretation of CAA section 111, each state is permitted to include compliance flexibilities, including flexibilities that allow affected EGUs to meet their emission limits in the aggregate, in their state plans. The EPA also explained that, in particular emission guidelines, the Agency may limit compliance flexibilities if necessary to protect the environmental outcomes of the guidelines.[943] Thus, in the subpart Ba final rule the EPA returned to its longstanding position that CAA section 111(d) authorizes the EPA to approve state plans that achieve the requisite emission limitation through aggregate reductions from their sources, including through trading or averaging, where appropriate for a particular emission guideline and consistent with the intended environmental outcomes under CAA section 111.[944]

In developing both the proposed and final emission guidelines, the EPA heard from stakeholders that flexibilities are important in complying with standards of performance under these emission guidelines. The EPA proposed to allow states to incorporate emission trading and averaging into their plans under these emission guidelines, provided that states ensure that the use of such flexibilities will result in an aggregate level of emission reduction that is equivalent to each source individually achieving its standard of performance.

Specifically, a variety of commenters from states, industry, RTO/ISOs, and NGOs emphasized the importance of allowing states to incorporate not only flexibilities that allow sources to demonstrate compliance in the aggregate, such as emission trading and averaging, but also unit-specific mass-based compliance into their plans. In particular, commenters expressed a strong preference for mass-based compliance mechanisms, whether unit-specific or emission trading, and cited reliability as a key driver of their support for such mechanisms. However, for the most part commenters did not provide detail on how flexibilities could be designed under the unique circumstances of these emission guidelines. In addition, many commenters did not specify as to the usefulness of certain compliance flexibilities for steam generating EGUs versus combustion turbine EGUs. Because these final emission guidelines only apply to steam generating EGUs, there are fewer affected EGUs that could partake in these flexibilities, which may limit their usefulness. A description of and responses to general comments on these compliance flexibilities can be found at the end of this subsection.

The EPA notes that many other features of the final emission guidelines provide the type of flexibility that the commenters stated they wanted through the use of emission trading, averaging, and/or unit-specific mass-based compliance. First, as noted in section X.C.1.b of this preamble, compliance with presumptively approvable rate-based standards of performance is demonstrated on an annual basis, which already provides flexibility around mass emissions over an annual period (*i.e.,* it affords the affected EGU the ability over the course of the year to vary its emission output, which may be useful if, for example, it needs to temporarily turn off its control equipment or otherwise increase its emission rate). Second, the EPA is finalizing two mechanisms, described in section XII.F of this preamble, to address reliability concerns raised by commenters: a short-term reliability mechanism that allows affected EGUs to operate above their standard of performance for a limited time in periods of emergency and a reliability assurance mechanism to ensure sufficient capacity is available. Finally, as described in section X.C.2 of this preamble, states may invoke RULOF to provide for less stringent standards of performance for affected EGUs under certain circumstances (states may invoke RULOF both at the time of initial state plan development as well as through state plan revision should the circumstances of an affected EGU change following state plan submission).

The EPA believes that the use of compliance flexibilities, within the parameters specified in these emission guidelines, may provide some additional operational flexibility to states and affected EGUs in achieving the required emission reductions which, under these emission guidelines, are achieved specifically through cleaner performance. In particular, for aggregate compliance flexibilities like emission averaging and trading, affected EGUs may be able to capitalize on heterogeneity in economic emission reduction opportunities based on minor differences in marginal emission abatement costs and/or operating parameters among EGUs. This heterogeneity may provide some incentive among participating EGUs to overperform (*i.e.,* operate even more cleanly than required by the applicable standard of performance, because of the opportunity to sell compliance

[943] 88 FR 80533 (November 17, 2023).

[944] The EPA has authorized trading or averaging as compliance methods in several emission guidelines. See, *e.g.,* 70 FR 28606, 28617 (May 18, 2005) (Clean Air Mercury Rule authorized trading) (vacated on other grounds); 40 CFR 60.24(b)(1) (subpart B CAA section 111 implementing regulations promulgated in 2005 allow states' standards of performance to be based on an ''allowance system''); 80 FR 64662, 64840 (October 23, 2015) (CPP authorizing trading or averaging as a compliance strategy). In the recent final emission guidelines for the oil and natural gas industry, the EPA also finalized a determination that states are permitted sources to demonstrate compliance in the aggregate. 89 FR 16820 (March 8, 2024).

instruments to other units), while also providing some limited opportunity for other sources to vary their emission output.

Therefore, the EPA is finalizing a determination that the use of compliance flexibilities, including emission trading, averaging, and unit-specific mass-based compliance, is permissible for affected EGUs in certain subcategories and in certain circumstances under these emission guidelines. Specifically, the EPA is allowing affected EGUs in the medium- and long-term coal-fired subcategories to utilize these compliance flexibilities. The scope of this allowance is tailored to ensure consistency with the fundamental principle under CAA section 111 that state plans maintain the stringency of the EPA's BSER determination and associated degree of emission limitation as applied through the EPA's presumptive standards of performance in the context of these emission guidelines. In addition, the EPA believes that the scope of this allowance is consistent and appropriate for providing an incentive for overperformance. Relatedly, the EPA is also providing further elaboration on what it means for states to demonstrate that implementation of a standard of performance using a rate- or mass-based flexibility is at least as stringent as unit-specific implementation of affected EGUs' standards of performance. States are not required to allow their affected EGUs to use compliance flexibilities but can provide for such flexibilities at their discretion. In order for the EPA to find that a state plan that includes such flexibilities is ''satisfactory,'' the state plan must demonstrate how it will achieve and maintain the requisite level of emission reduction.

The EPA stresses that any flexibilities involving aggregate compliance would be used to demonstrate compliance with an already-established standard of performance, rather than be used to establish a standard of performance in the first instance. The presumptive standards of performance that the EPA is providing in these emission guidelines are based on control strategies that are applied at the level of individual units. A compliance flexibility may change the way an affected EGU demonstrates compliance with a standard of performance (*e.g.,* by allowing that EGU to surrender allowances from another unit in lieu of reducing a portion of its own emissions), but does not alter the benchmark of emission performance against which compliance is evaluated. This is in contrast to the RULOF mechanism, which, as described in section X.C.2 of this preamble, states may use to apply a different standard of performance with a different degree of emission limitation than the EPA's presumptive standard. States incorporating trading or averaging would not need to undergo a RULOF demonstration for sources participating in trading or averaging programs because they are not altering those sources' underlying standards of performance—just providing an additional way for sources to demonstrate compliance.

While the EPA acknowledges widespread interest in the use of mass-based compliance, in the context of these particular emission guidelines, the Agency has significant concerns about the ability to demonstrate that mass-based compliance approaches achieve at least equivalent emission reduction as the application of rate-based, source-specific standards of performance. As explained in further detail in sections X.D.4 and X.D.5, the EPA is requiring the use of a backstop emission limitation, or backstop rate, in conjunction with mass-based compliance approaches (*i.e.,* for both unit-specific mass-based compliance and mass-based emission trading) for both the long-term and medium-term coal-fired subcategories. However, the EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach only for affected EGUs in the long-term subcategory. The use of mass-based compliance approaches—both unit-specific and trading—for affected EGUs in the medium-term coal-fired subcategory in particular poses a high risk of undermining the stringency of these emission guidelines due to inherent uncertainty about the future utilization of these sources. While the EPA is not precluding states from attempting to design mass-based approaches for affected EGUs in the medium-term coal-fired subcategory that satisfy the requirement of achieving at least equivalent stringency as rate-based implementation, the Agency was unable to devise an appropriate, implementable presumptively approvable approach for affected EGUs in the medium-term coal-fired subcategory and is therefore not providing one here. The EPA is also not providing a presumptively approvable approach to emission trading or averaging. Instead, the EPA intends to review emission trading or averaging programs in state plans on a case-by-case basis against the foundational principles for consistency with CAA section 111, as discussed in this section of the preamble.

Section X.D.1 of this preamble discusses the fundamental requirement that compliance flexibilities maintain the level of emission reduction of unit-specific implementation, in order to inform states' consideration of such flexibilities for any use in their state plans. It also addresses why limitations on the use of compliance flexibilities for certain subcategories are necessary to maintain the intended environmental outcomes of these emission guidelines. Sections X.D.2, X.D.3, X.D.4, and X.D.5 discuss each available type of compliance flexibility and provide information on how they can be used in state plans under these emission guidelines. Section X.D.6 provides information on general implementation features of emission trading and averaging programs that states must consider if they develop such a program. Section X.D.7 discusses interstate emission trading. Finally, section X.D.8 discusses considerations related to existing state programs and the inclusion of compliance flexibilities in a state plan under these emission guidelines.

Comment: Commenters cited a variety of reasons supporting the use of compliance flexibilities, such as emission trading, averaging, and unit-specific mass-based compliance, in these emission guidelines, including the need for flexibility in meeting the degree of emission limitation defined by the BSER, the potential for more cost-effective compliance, and reliability purposes.

Response: The EPA believes that, in certain circumstances, these flexibilities can provide some operational and cost flexibility to states and affected EGUs in complying with these emission guidelines and their standards of performance in state plans. However, as described above, the EPA is addressing reliability-related concerns primarily through other structural changes and mechanisms under these emission guidelines (see section XII.F of this preamble) that may obviate the need to use compliance flexibilities specifically to address reliability concerns. As a general matter, the EPA believes that compliance flexibilities such as emission trading and averaging provide some incentive for overperformance that could be beneficial to states and affected EGUs.

The EPA is finalizing a determination that emission trading, averaging, and unit-specific mass-based compliance are permissible for certain subcategories under these emission guidelines, subject to the limitations described in section X.D.1 of this preamble. The EPA believes these limitations are necessary

in the context of these emission guidelines in order to maintain the level of emission reduction of the EPA's BSER determination and corresponding degree of emission limitation.

Comment: Some commenters expressed opposition to the use of emission trading and averaging, citing the potential for emission trading and averaging programs to maintain or exacerbate existing disparities in communities with environmental justice concerns.

Response: The EPA is cognizant of these concerns and believes that emission trading and averaging are not necessarily incompatible with environmental justice. The EPA is including limitations on the use of compliance flexibilities in state plans that should help address these EJ concerns. As discussed in more detail in section X.D.1, the EPA is restricting certain subcategories from using trading or averaging as well as, for mass-based compliance mechanisms, requiring the use of a backstop rate, to ensure that the use of compliance flexibilities maintains the level of emission reduction of the EPA's BSER determination and corresponding degree of emission limitation as well as achieves the statutory objective of these emission guidelines to mitigate air pollution by requiring sources to operate more cleanly. The EPA notes that trading programs can be designed to include measures like unit-specific emission rates that assure that reductions and corresponding benefits accrue proportionally to communities with environmental justice concerns. The EPA also notes that states have the ability to add further features and requirements to emission trading and averaging programs than identified in these emission guidelines, or to forgo their use entirely.

Pursuant to the requirements of subpart Ba, states are required to conduct meaningful engagement on all aspects of their state plans with pertinent stakeholders. This would necessarily include any potential use of flexibilities for sources to demonstrate compliance with the proposed standards of performance through emissions trading or averaging. As discussed in greater detail in section X.E.1.b.i of this preamble, meaningful engagement provides an opportunity for communities most affected by and vulnerable to the impacts of a plan to provide input, including input on any impacts resulting from the use of compliance flexibilities.

Comment: Some commenters stated that allowing trading or averaging is not consistent with the legal opinion in *West Virginia* v. *EPA.*

Response: This comment is outside the scope of this action. The EPA finalized its interpretation that CAA section 111 does not preclude states from including compliance flexibilities such as trading or averaging in their state plans (although the EPA may limit those flexibilities in particular emission guidelines if necessary to protect the environmental outcomes of those guidelines) when it revised the CAA section 111(d) implementing regulations in subpart Ba.[945] As described in the final subpart Ba revisions, ''in *West Virginia* v. *EPA,* the Supreme Court did not directly address the state's authority to determine their sources' control measures. Although the Court did hold that constraints apply to the EPA's authority in determining the BSER, the Court's discussion of CAA section 111 is consistent with the EPA's interpretation that the provision does not preclude states from granting sources compliance flexibility.'' [946] The EPA further explained in the preamble to the subpart Ba final rule that the *West Virginia* Court was clear that the focus of the case was exclusively on whether the EPA acted within the scope of its authority in establishing the BSER: ''The Court did not identify any constraints on the states in establishing standards of performance to their sources, and its holding and reasoning cannot be extended to apply such constraints.'' [947]

The EPA reiterates that, under these emission guidelines, the BSER determinations are emission reduction technologies or strategies that apply to and reduce the emission rates of individual affected EGUs. Furthermore, states have the option of including emission trading or averaging in their states plans but are by no means required to do so. States that choose to include trading or averaging programs in their state plans are required to demonstrate that those programs are in the aggregate as stringent as each affected EGU individually achieving its rate-based standard of performance. Additionally, as explained elsewhere in sections X.D.4 and X.D.5 of this preamble, the EPA is requiring the use of a backstop emission rate in conjunction with mass-based compliance flexibilities, one result of which is that units cannot comply with their standards of performance merely by shifting their generation to other electricity generators. Therefore, the EPA's BSERs in these emission guidelines are not based on generation shifting and, even if the EPA believed that *West Virginia* v. *EPA* implicated the use of compliance flexibilities, the permissible use of trading and averaging in this particular case does not implicate the Court's concerns about generation shifting therein.

1. Demonstrating Equivalent Stringency

As stated in the section above, states are permitted to use emission trading, averaging, and unit-specific mass-based compliance in their plans for certain subcategories under these emission guidelines, provided that the plan demonstrates that any such use will achieve a level of emission reduction that is in the aggregate as environmentally protective as each affected EGU achieving its rate-based standard of performance. This requirement is rooted in the structure and purpose of CAA section 111. Most commenters supported the use of compliance flexibilities in these emission guidelines, and many explicitly expressed support for the EPA's stringency criterion in this context. Commenters also requested greater clarity on how to demonstrate equivalent stringency in a state plan. In this section, the EPA describes foundational parameters for a demonstration of equivalence in the state plan as well as limitations on the availability of compliance flexibilities for certain affected EGUs, which stem from the EPA's stringency criterion. Additionally, the EPA offers further explanation of how it will review state plan submissions to determine whether plans that include compliance flexibilities achieve an equivalent (or greater) level of emission reduction as each affected EGU individually complying with its unit-specific rate-based standard of performance.

a. Requirements for Demonstrating Equivalent Stringency

In their plans, states incorporating compliance flexibilities must first clearly demonstrate how they calculated the aggregate rate-based emission limitation (for rate-based averaging), mass limit (for unit-specific mass-based compliance), or mass budget (for mass-based emission trading) from unit-specific, rate-based presumptive standards of performance. (For rate-based trading, the standard of performance coupled with, if necessary, an adjustment based on the acquisition of compliance instruments, is used to demonstrate compliance.) In doing so, states must identify the specific affected EGUs that will be using compliance flexibilities; which flexibility each unit

[945] 88 FR 80480 80533–35 (November 17, 2023).

[946] 88 FR 80534 (November 17, 2023).

[947] 88 FR 80535 (November 17, 2023).

will able to use; the unit-specific, rate-based presumptive standard of performance; and the standard of performance established in the plan for each unit (rate-based limit or mass limit) or set of units (aggregate rate-based emission limitation or mass budget). The state must document and justify the assumptions made in calculating an aggregate rate-based emission limitation, mass limit, or mass budget, such as how the calculation is weighted or, for mass-based mechanisms, the level of utilization of participating affected EGUs used to calculate the mass limit or budget. This requirement is discussed in more detail in the context of each type of compliance flexibility in the following subsections.

Next, states must demonstrate how the compliance flexibility will maintain the requisite stringency, *i.e.,* how the plan will maintain the aggregate level of emission reduction that would be achieved if each unit was individually complying with its rate-based standard of performance. As discussed in section X.C.1 of this preamble, an affected EGU's standard of performance must generally be no less stringent than the corresponding presumptive standard of performance under these emission guidelines. This is true regardless of whether a standard of performance is expressed in terms of rate or mass. However, under an aggregate compliance approach, a unit may demonstrate compliance with that standard of performance by averaging its emission performance or trading compliance instruments (*e.g.,* allowances) with other affected EGUs. Here, to ensure consistency with the level of emission reductions Congress expected under CAA section 111(a)(1), the state must also demonstrate that the plan overall achieves equivalent stringency, *i.e.,* the same or better environmental outcome, as applying the EPA's presumptive standards of performance to each affected EGU (after accounting for any application of RULOF). That is, in order for the EPA to find a state plan ''satisfactory,'' that plan must achieve at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance (again, after accounting for any application of RULOF).

The requirement that state plans achieve equivalent stringency to the EPA's degree of emission limitation flows from the structure and purpose of CAA section 111, which is to mitigate air pollution that is reasonably anticipated to endanger public health or welfare. It achieves this outcome by requiring source categories that cause or contribute to dangerous air pollution to operate more cleanly. Unlike the CAA's NAAQS-based programs, section 111 is not designed to reach a level of emissions that has been deemed ''safe'' or ''acceptable''; there is no air-quality target that tells states and sources when emissions have been reduced ''enough.'' Rather, CAA section 111 requires affected sources to reduce their emissions to the level that the EPA has determined is achievable through application of the best system of emission reduction, *i.e.,* to achieve emission reductions consistent with the applicable presumptive standard of performance. Consistent with the statutory purpose of requiring affected sources to operate more cleanly, the EPA typically expresses presumptive standards of performance as rate-based emission limitations (*i.e.,* limitations on the amount of a regulated pollutant that can be emitted per unit of output, per unit of energy or material input, or per unit of time).

In the course of complying with a rate-based standard of performance under a state plan, an affected source takes actions that may or may not affect its ongoing emission reduction obligations. For example, a source may take certain actions that remove it from the source category, *e.g.,* by switching fuel type or permanently ceasing operations. Upon doing so, the source is no longer subject to the emission guidelines. Or an affected source may choose to change its operating characteristics in a way that impacts its overall mass of emissions, *e.g.,* by changing its utilization, in which case the source is still required to reduce its emission rate consistent with cleaner performance. In either instance, the changes in operation to one affected source do not implicate the obligations of other affected sources. Although changes to certain sources' operation may reduce emissions from the source category, they do not absolve the remaining affected EGUs from the statutory obligation to reduce their emission rates consistent with the level that the EPA has determined is achievable through application of the BSER. While state plans may, when permitted by the applicable emission guidelines, allow affected sources to translate their rate-based presumptive standards of performance into mass limits and/or comply with their standards of performance in the aggregate through averaging or trading, the fundamental statutory requirement remains: the state plan must demonstrate that, even if individual affected sources are not necessarily achieving their presumptive rate-based standards of performance, the plan as a whole must provide for the same level of emission reduction for the affected EGUs as though they were. While states may choose to allow individual sources to emit more or less than the degree of emission limitation determined by the EPA, any compliance flexibilities must be designed to ensure that their use does not erode the emission reduction benefits that would result if each source was individually achieving its presumptive standard of performance (after accounting for any use of RULOF).

For rate-based averaging and trading, discussed in more detail in sections X.D.2 and X.D.3 of this preamble, demonstrating an equivalent level of emission reduction is relatively straightforward, as a rate-based program inherently provides relatively stronger assurance of equivalence with individual rate-based standards of performance. This is due to the fact that the aggregate rate-based emission limitation (for rate-based averaging) or rate-based standard of performance with adjustment for compliance instruments (for rate-based trading) is calculated based on both the emission output and gross generation output (utilization) of the participating affected EGUs. In other words., a rate-based compliance flexibility, such as a rate-based unit-specific standard of performance, inherently adjusts for changes in utilization and preserves the imperative to operate more cleanly. For unit-specific mass-based compliance and mass-based trading, demonstrating equivalent stringency is more complicated, as the use of a mass limit or mass budget on its own may not guarantee that sources are achieving emission reductions commensurate with operating more cleanly. Thus the EPA is requiring that, in order to ensure that the emission outcome that would be achieved through unit-specific rate-based standards of performance are preserved, states must also include a backstop emission rate limitation, or backstop rate, for affected EGUs using a mass-based compliance flexibility, as discussed in more detail in sections X.D.4 and X.D.5 of this preamble. In addition, states employing a mass-based mechanism in their plans must show why assumptions underlying the calculation of utilization for the purposes of establishing a mass limit or mass budget are appropriately conservative to ensure an equivalent level of emission reduction, as discussed more in sections X.D.4 and X.D.5 of this preamble.

In sum, states wishing to employ compliance flexibilities in their state

plans must demonstrate that the plan achieves at least equivalent stringency with each source individually achieving its standard of performance, bearing in mind the discussion and requirements in this section, as well as the discussion and requirements in the following sections specific to each type of mechanism. The EPA will review state plan submissions that include compliance flexibilities to ensure that they are consistent with CAA section 111's purpose of reducing dangerous air pollution by requiring sources to operate more cleanly. In order for the EPA to find a state plan ''satisfactory,'' that plan must address each affected EGU within the state and demonstrate that the plan overall achieves at least the level of emission reduction that would result if each affected EGU was achieving its presumptive standard of performance, after accounting for any application of RULOF.

b. Exclusion of Certain Affected EGUs From Compliance Flexibilities

While the use of compliance flexibilities such as emission trading, averaging, and unit-specific mass-based compliance is generally permissible under these emission guidelines, the EPA indicated in the proposal that it may be appropriate for certain groups of sources to be excluded from using these flexibilities in order to ensure an equivalent level of emission reduction with each source individually achieving its standard of performance. In the proposed emission guidelines, the EPA expressed concerns about the use of compliance flexibilities for several subcategories that have BSER determinations of routine methods of operation and maintenance as well as those sources for which states have invoked RULOF to apply a less stringent standard of performance, as their inclusion may undermine the intended level of emission reduction of the BSER for other facilities. The EPA also questioned whether trading and averaging across subcategories should be limited in order to maintain the stringency of unit-specific compliance. Finally, the EPA questioned whether affected EGUs that receive the IRC section 45Q tax credit for permanent sequestration of CO_2 may have an overriding incentive to maximize both the application of the CCS technology and total electric generation, leading to source behavior that may be non-responsive to the economic incentives of a trading program.

In response to the request for comment on these concerns related to the appropriateness of emission trading and averaging for certain subcategories and for sources with a standard based on RULOF, the EPA received mixed feedback. Some commenters agreed with the EPA's concerns about these subcategories participating in trading and averaging and that affected EGUs in these subcategories should be prevented from participating in an emission trading or averaging program. However, several commenters said that it was indeed appropriate to allow all subcategories as well as sources with a standard of performance based on RULOF to participate in trading and averaging and that the program would still achieve an equivalent level of emission reduction, even if those subcategories are of limited stringency.

In response to the request for comment on whether emission trading and averaging should be allowed across subcategories in light of concerns over differing levels of stringency for different subcategories impacting overall achievement of an equivalent level of emission reduction, the EPA also received mixed feedback. Some commenters supported restricting trading and averaging across subcategories because of concerns that EGUs in a subcategory with a relatively higher stringency could acquire allowances from EGUs in a subcategory with a relatively lower stringency in order to comply instead of operating a control technology. Several commenters stated that trading across subcategories need not be limited because, as long as state plans are of an equivalent level of emission reduction, emission trading and averaging would still require the overall aggregate limit to be met.

Taking into consideration the comments on the proposed emission guidelines as well as changes made to the subcategories in the final emission guidelines, the Agency is finalizing the following restrictions on the use of compliance flexibilities by certain subcategories.

First, emission trading or averaging programs must not include affected EGUs for which states have invoked RULOF to apply less stringent standards of performance. The Agency believes that, because RULOF sources have a standard of performance tailored to individual source circumstances that is required to be as stringent as reasonably practicable, these sources should not need further operational flexibility and are also unlikely to be able to overperform to any significant or regular degree. This means that their participation in an emission trading or averaging program is, at best, unlikely to add any value to the program (in terms of opportunity for overperformance) or, at worst, may provide an inappropriate opportunity for other sources subject to a relatively more stringent presumptive standard of performance to underperform by obtaining compliance instruments from or averaging their emission performance with affected EGUs that are subject to a relatively less stringent standard of performance based on RULOF. This outcome undermines the ability of the state plan to demonstrate an equivalent level of emission reduction, as non-RULOF sources would face a reduced incentive to operate more cleanly. In addition, affected EGUs with a standard of performance based on RULOF are prohibited from using unit-specific mass-based compliance under these emission guidelines. This is due to the compounding uncertainty regarding how states will use RULOF to particularize the compliance obligations for an affected EGU and the future utilization of affected EGUs that may be subject to RULOF. The RULOF provisions are used where a particular EGU is in unique circumstances and may result in a less stringent standard of performance based on the BSER technology, a less stringent standard of performance based on a different control technology, a longer compliance schedule, or some combination of the three. The bespoke nature of compliance obligations pursuant to RULOF makes it difficult for the EPA to provide principles for and for states to design mass-based compliance strategies that ensure an equivalent level of emission reduction. Additionally, as previously discussed, there is a significant amount of uncertainty in the future utilization of certain affected EGUs, including those with standards of performance pursuant to RULOF. While there is no risk of implicating the compliance obligation of other sources in unit-specific mass-based compliance, the EPA believes that allowing RULOF sources to use unit-specific mass compliance would pose a significant risk in undermining the stringency of the state plan such that these sources may not be achieving the level of emission reduction commensurate with cleaner performance.

Second, emission trading or averaging programs may not include affected EGUs in the natural gas- and oil-fired steam subcategories. The BSER determination and associated degree of emission limitation for affected EGUs in these subcategories do not require any improvement in emission performance and already offer flexibility to sources to account for varying efficiency at different operating levels. As a result, these sources are unlikely to be

responsive to an incentive towards overperformance, which means that their participation in an emission trading or averaging program is unlikely to add any value to the program (in terms of opportunity for overperformance). In addition, the EPA is concerned that the participation of these sources may undermine the program's equivalence with the presumptive standards of performance, because other steam sources, which have a relatively more stringent degree of emission limitation, may be inappropriately incentivized to underperform by obtaining compliance instruments from or averaging their emission performance with affected EGUs in the natural gas- and oil-fired steam subcategories. This outcome undermines the ability of the state plan to demonstrate equivalent stringency by reducing the incentive for sources to operate more cleanly. In addition, affected EGUs in the natural gas- and oil-fired steam subcategories are prohibited from using unit-specific mass-based compliance. While there is no risk of implicating the compliance obligation of other sources in unit-specific mass-based compliance, the EPA believes, as previously stated, there is already sufficient flexibility offered to sources in the natural gas- and oil-fired steam subcategories, as the basis for subcategorizing these sources takes into account their varying efficiency at different operating levels.

The EPA is allowing both coal-fired subcategories (both the medium- and long-term) to participate in all types of compliance flexibilities, within the parameters set by the EPA described in the following sections. The Agency believes, and many commenters agreed, that affected EGUs taking advantage of the IRC section 45Q tax credit may still benefit from the operational flexibility provided by emission trading and averaging, as well as unit-specific mass-based compliance. The Agency also believes that overperformance among these sources is possible and worth incentivizing through the use of compliance flexibilities. Incentivizing overperformance can lead to innovation in control technologies that, in turn, can lead to lower costs for, and greater emissions reductions from, control technologies.

The EPA is not finalizing a restriction on trading or averaging across subcategories for the two subcategories that are permitted to participate in these flexibilities. This means that affected EGUs in the medium-term coal-fired subcategory may trade or average their compliance with affected EGUs in the long-term coal-fired subcategory. With the aforementioned restrictions on participation in trading and averaging, the EPA does not see a need to further restrict the ability of eligible sources to trade or average with other sources.

2. Rate-Based Emission Averaging

The EPA proposed to permit states to incorporate rate-based averaging into their state plans under these emission guidelines. In general, rate-based averaging allows multiple affected EGUs to jointly meet a rate-based standard of performance. The scope of such averaging could apply at the facility level (*i.e.,* units located within a single facility) or at the owner or operator level (*i.e.,* units owned by the same utility). A description of and responses to comments received on rate-based averaging can be found at the end of this subsection.

As discussed in the proposed emission guidelines, averaging can provide potential benefits to affected sources by allowing for more cost effective and, in some cases, more straightforward compliance. First, averaging offers some flexibility for owners or operators to target cost effective reductions at certain affected EGUs. For example, owners or operators of affected EGUs might target installation of emission control approaches at units that operate more. Second, averaging at the facility level provides greater ease of compliance accounting for affected EGUs with a complex stack configuration (such as a common- or multi-stack configuration). In such instances, unit-level compliance involves apportioning reported emissions to individual affected EGUs that share a stack based on electricity generation or other parameters; this apportionment can be avoided by using facility-level averaging.

The EPA is finalizing a determination that rate-based averaging is permissible for affected EGUs in the medium- and long-term coal-fired subcategories. The scope of rate-based averaging may be at the facility level or at the owner/operator level within the state, as these are the circumstances under which rate-based averaging can provide significant benefits, as identified above, with minimal implementation complexity. Above this level (*i.e.,* across owner/operators or at the state or interstate level), the EPA has determined that a rate-based compliance flexibility must be implemented through rate-based trading, as described in section X.D.3 of this preamble. The EPA is establishing this limitation on the scope of averaging because it believes that the level of complexity associated with utilities, independent power producers, and states attempting to coordinate the real-time compliance information needed to assure that either all affected EGUs are meeting their individual standard of performance, or that a sufficient number of affected EGUs are overperforming to allow operational flexibility for other affected EGUs such that the aggregate standard of performance is being achieved, would curtail transparency and limit states', the EPA's, and stakeholders' abilities to track timely compliance. For example, dozens of units trying to average their emission rates would require owners or operators from different utilities and independent power producers to share operating and emissions data in real time. Thus, due to likely limitations on the timely availability of compliance-related information across owners and operators and across states, which is necessary to ensure aggregate compliance, the EPA believes that it is appropriate to limit the scope of rate-based averaging to the facility level or the owner/operator level within one state in order to provide greater compliance certainty and thus better demonstrate an equivalent level of emission reduction.

Demonstrating equivalence with unit-specific implementation of rate-based standards of performance in a rate-based averaging program is straightforward. A state would need to specify in its plan the group of affected EGUs participating in the averaging program that will demonstrate compliance on an aggregate basis, the unit-specific rate-based presumptive standard of performance that would apply to each participating affected EGU, and the aggregate compliance rate that must be achieved for the group of participating affected EGUs and how that aggregate rate is calculated, as described below. For states incorporating owner/operator-level averaging, the state plan would also need to include provisions that specify how the program will address any changes in the owner/operator for one or more participating affected EGUs during the course of program implementation to ensure effective implementation and enforcement of the program. Such provisions should be specified upfront in the plan and be self-executing, such that a state plan revision is not required to address such changes.

To ensure an equivalent level of emission reduction with application of individual rate-based standards of performance, the EPA is requiring that the weighting of the aggregate compliance rate is done on an output basis; in other words, participating affected EGUs must demonstrate

compliance through achievement of an aggregate CO_2 emission rate that is a gross generation-based weighted average of the required standards of performance of each of the affected EGUs that participate in averaging. Such an approach is necessary to ensure that the aggregate compliance rate is representative of the unit-specific standards of performance that apply to each of the participating affected EGUs. Commenters were generally supportive of this method of calculating an aggregate rate for a group of sources participating in averaging. The Agency emphasizes that only affected EGUs are permitted to be included in the calculation of an aggregate rate-based standard of performance as well as in an aggregate compliance demonstration of a rate-based standard of performance.

Comment: Commenters supported the use of rate-based averaging on the grounds that it can provide operational flexibility to affected EGUs as well as the opportunity for owners and operators to optimize control technology investments. Many commenters supported averaging at the facility- and owner/operator-level as well as on a statewide or interstate basis.

Response: The EPA believes that rate-based trading can provide some additional operational flexibility and is finalizing that rate-based averaging is permissible at the facility- and owner/operator-level for affected EGUs in the medium- and long-term coal-fired subcategories. However, for reasons discussed above, the EPA believes that rate-based trading, rather than rate-based averaging, should be implemented where a state would like to implement a rate-based compliance flexibility at a state or interstate basis.

3. Rate-Based Emission Trading

The EPA proposed to permit states to incorporate rate-based trading into their state plans under these emission guidelines. In general, a rate-based trading program allows affected EGUs to trade compliance instruments that are generated based on their emission performance. A description of and responses to comments on rate-based trading can be found at the end of this subsection.

The EPA notes that, like rate-based averaging, rate-based trading can provide some flexibility for owners or operators to target cost effective reductions at specific affected EGUs, but can heighten the flexibility relative to averaging by further increasing the number of participating affected EGUs. In addition, emission trading can provide incentive for overperformance.

The proposed emission guidelines described how rate-based trading could work in this context. First, the EPA discussed how it expects states to denote the tradable compliance instrument in a rate-based trading programs as one ton of CO_2. A tradable compliance instrument denominated in another unit of measure, such as a MWh, is not fungible in the context of a rate-based emission trading program. A compliance instrument denominated in MWh that is awarded to one affected EGU most likely does not represent an equivalent amount of emissions credit when used by another affected EGU to demonstrate compliance, as the CO_2 emission rates (lb CO_2/MWh) of the two affected EGUs are likely to differ.

Each affected EGU is required under these emission guidelines to have a particular standard of performance, based on the degree of emission limitation achievable through application of the BSER, with which it would have to demonstrate compliance. Under a rate-based trading program, affected EGUs performing at a CO_2 emission rate below their standard of performance would be awarded compliance instruments at the end of each calendar year denominated in tons of CO_2. The number of compliance instruments awarded would be equal to the difference between their standard of performance CO_2 emission rate and their actual reported CO_2 emission rate multiplied by their gross generation in MWh. Affected EGUs demonstrating compliance through a rate-based averaging program that are performing worse than their standard of performance would be required to obtain and surrender an appropriate number of compliance instruments when demonstrating compliance, such that their demonstrated CO_2 emission rate is equivalent to their rate-based standard of performance. Transfer and use of these compliance instruments would be accounted for in the numerator (sum of total annual CO_2 emissions) of the CO_2 emission rate as each affected EGU performs its compliance demonstration. Compliance would be demonstrated for an affected EGU based on its reported CO_2 emission performance (in lb CO_2/MWh) and, if necessary, the surrender of an appropriate number of tradable compliance instruments, such that the demonstrated lb CO_2/MWh emission performance is equivalent to (or lower than) the rate-based standard of performance for the affected EGU.

The EPA is finalizing a determination that rate-based trading is permissible for affected EGUs in the medium- and long-term coal-fired subcategories. The Agency notes, as previously discussed, that rate-based trading (rather than averaging) must be utilized if the state wishes to establish a statewide or interstate rate-based compliance flexibility, in order to ensure compliance and equivalent stringency. For similar reasons, rate-based trading should also be utilized in lieu of owner/operator-level averaging when an owner/operator wishes to use a rate-based compliance flexibility for a group of its units that are located in more than one state.

Demonstrating equivalence with unit-specific implementation of rate-based standards of performance in a rate-based trading program is relatively straightforward. States would need to specify in their plans the affected EGUs participating in the trading program and their individual standards of performance. Under the method of rate-based trading described in this section, a compliance demonstration would be done for each participating affected EGU based on a combination of the reported emission performance and, if relevant, the surrender of compliance instruments. In addition, the EPA is requiring that the compliance instrument be denominated as one ton of CO_2 (rather than another unit such as MWh). The Agency believes this requirement is necessary to ensure an equivalent level of emission reduction as application of individual rate-based standards of performance.

An additional aspect of demonstrating equivalence is ensuring that the program achieves and maintains an equivalent level of emission reduction with standards of performance over time, which is much more certain in a rate-based trading program than in a mass-based program. Unlike mass-based trading programs, under which states must make assumptions about units' future utilization that may become inaccurate as those units' operations shift over time, rate-based trading programs do not rely on utilization assumptions. Utilization is already accounted for by default in a rate-based trading program. Thus, while mass-based compliance flexibilities require additional design features to ensure the continued accuracy of assumptions about utilization and thus emission limits or budgets over time, such features are not necessary in a rate-based trading program.

Comment: While commenters broadly supported the use of rate-based emission trading under these emission guidelines, as it provides operational flexibility to affected EGUs, some commenters expressed concern that

rate-based trading could lead to an absolute increase in emissions.

Response: The EPA notes that, as a general matter, CAA section 111 reduces emissions of dangerous air pollutants by requiring affected sources to operate more cleanly. Under the construct of these emission guidelines, so long as a rate-based trading program is appropriately designed to maintain the level of emission reduction that would be achieved through unit-specific, rate-based standards of performance, it would be consistent with CAA section 111.

4. Unit-Specific Mass-Based Compliance

Although the EPA discussed mass-based trading in the proposed emission guidelines, it did not specifically address whether states may include a related flexibility, unit-specific mass-based compliance, in their plans. Several commenters supported mass-based mechanisms, including both unit-specific mass-based compliance and mass-based trading. A description of and responses to comments on unit-specific mass-based compliance can be found at the end of this subsection.

The EPA's CAA section 111 implementing regulations generally permit states to include mass-based limits in their plans, see 40 CFR 60.21a(f), subject to the requirement that standards of performance must be no less stringent than the presumptive standards of performance in the corresponding emission guidelines. 40 CFR 60.24a(c). However, the EPA has significant concerns about the use of unit-specific mass-based compliance in the context of these emission guidelines and the ability of states using this mechanism to ensure that such use will result in the same level of emission reduction that would be achieved by applying the rate-based standard of performance. These concerns arise both from the particular focus of these emission guidelines on emission reduction strategies that result in cleaner performance of affected EGUs, and the inherent uncertainty in predicting the utilization of affected EGUs during the compliance period, especially given the long lead times provided.

Therefore, while the EPA is allowing states to include unit-specific mass-based compliance in their plans for affected coal-fired EGUs in the medium- and long-term subcategories, it is also requiring states to use a backstop emission rate in conjunction with the mass-based compliance demonstration. As discussed in section X.D.1 of this preamble, the EPA believes the use of a backstop rate is consistent with the focus on achieving cleaner performance. CAA section 111 requires the mitigation of dangerous air pollution, which is generally achieved under this provision by requiring affected sources to operate more cleanly. Thus, standards of performance are typically expressed as a rate. In these emission guidelines, in particular, the BSERs for affected EGUs are control technologies and other systems of emission reduction that reduce the amount of CO_2 emitted per unit of electricity generation. The EPA is not precluding states from translating those unit-specific rate-based standards of performance into a mass-based limit (for unit-specific mass-based compliance) or budget (for emission trading). However, in order to ensure that the emission reductions required under CAA section 111 are achieved, mass-based limits or budgets must be accompanied by a backstop rate for purposes of demonstrating compliance. In addition, for coal-fired EGUs in the medium-term coal-fired subcategory in particular, it is critical that states' assumptions about future utilization do not result in inaccurate mass-based limits or budgets that allow units to emit more than they would be permitted to under unit-specific, rate-based compliance.

The EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach for affected EGUs in the long-term coal-fired subcategory, including a methodology for the applicable backstop rate, but is not finalizing a presumptively approvable approach for affected EGUs in the medium-term coal-fired subcategory. As explained below, the EPA has not been able to determine a unit-specific mass-based compliance mechanism for medium-term coal-fired EGUs that would ensure that the mass limit is no less stringent than the presumptive standard of performance under these emission guidelines.

In general, unit-specific mass-based compliance establishes a budget of allowable mass emissions (a mass limit) for an individual affected EGU based on the degree of emission limitation defined by its subcategory and a specified level of anticipated utilization. Standards of performance would be provided in the form of mass limits in tons of CO_2 for each individual affected EGU, and compliance would be demonstrated through surrender of allowances, with each allowance representing a permit to emit one ton of CO_2. Unlike mass-based emission trading, under a unit-specific mass compliance mechanism, these allowances would not be tradable with other affected EGUs. To demonstrate compliance, the affected EGU would be required to surrender allowances in a number equal to its reported CO_2 emissions during each compliance period.

As detailed in section VII.C.1.a.i(B)(7), for affected coal-fired EGUs in the long-term subcategory that are installing CCS, considering the potential impacts of variable load, startups, and shutdowns, 90 percent CO_2 capture is, in general, achievable over the course of a year. However, the EPA believes unit-specific mass-based compliance could provide some benefit by affording long-term affected coal-fired EGUs that adopt this mechanism even greater operational flexibility.[948] For example, if an affected EGU encounters challenges related to the start-up of the CCS technology or needs to conduct maintenance of the capture equipment, unit-specific mass-based compliance would provide a path for the affected EGU to continue operating. At the same time, unit-specific mass-based compliance coupled with a backstop rate would generally ensure that units operate more cleanly and that the required level of emission reduction is achieved. As explained in more detail below, the EPA's confidence regarding the equivalent stringency of this mass-based compliance approach for units in the long-term subcategory depends on the Agency's confidence in the likely utilization of a unit that has adopted emissions controls—in this case, CCS.

For affected EGUs in the long-term coal-fired subcategory, the EPA is providing a presumptively approvable approach to unit-specific mass-based compliance. To establish the presumptively approvable mass limit, the presumptively approvable rate (as described in section X.C.1.b.i of this preamble) would be multiplied by a level of gross generation (*i.e.,* utilization level) corresponding to an annual capacity factor of 80 percent, which is the capacity factor used for the BSER analysis (see section VII.C.1.a.ii of this preamble) and represents expected utilization based on the incentive provided by the IRC section 45Q tax credit. In addition, under this approach, affected EGUs would need to meet a backstop emission rate, expressed in lb CO_2 per MWh on a gross basis, equivalent to a reduction relative to baseline emission performance of 80 percent, on an annual calendar-year basis. The EPA believes this backstop rate represents a reasonable level of operational flexibility for affected EGUs

[948] States may also elect to include the short-term reliability mechanism described in section XII.F.3.a in their plans to address grid emergency situations.

in the long-term subcategory, and it could provide flexibility for sources to employ other technologies (*e.g.,* membrane and chilled ammonia capture technologies) that can achieve a similarly high degree of emission limitation to CCS with amine-based capture. States may deviate from this approach (however, as previously discussed, the approach must include a backstop rate) and deviations will be reviewed to ensure consistency with the statute and this rule when the EPA reviews the state plan. For example, states may wish to use an assumed utilization level of greater than 80 percent to establish a mass limit. In reviewing such an approach for reasonableness, the EPA would consider, among other things, whether an affected EGU's capacity factor has historically been greater than 80 percent for any continuous 8 quarters of data. The EPA would review the supporting data and resulting mass limit for consistency with the statute. The EPA has confidence that the presumptively approvable approach achieves an equivalent level of emission reduction as the implementation of the individual presumptive standard of performance because of the high degree of stringency associated with this subcategory as well as the 45Q tax credit, which incentivizes units to maximize capture of CO_2 as well as the utilization of the affected EGU.

On the other hand, the EPA does not have the same confidence in a mass-based approach to unit-specific compliance for the medium-term coal-fired subcategory for two reasons: the uncertainty in the utilization of these affected EGUs and the relatively lower stringency of the subcategory (*i.e.,* 16 percent reduction relative to baseline emission performance), particularly as compared to the long-term subcategory. The EPA has not been able to develop a workable approach to mass-based compliance for these units that both preserves the stringency of the presumptive standard of performance and results in an implementable program for affected EGUs.

First, there are significant challenges in selecting an appropriate utilization assumption for the purposes of generating a mass limit for affected EGUs in the medium-term subcategory. When setting the mass limit for a future time period, as would occur in a state plan under these emission guidelines, assumptions about the source's anticipated level of utilization must be made. Estimating future utilization of affected EGUs in the medium-term subcategory is subject to a significant degree of uncertainty, driven by sector-wide factors including changes in relative fuel prices, new incentives for technology deployment provided by the IIJA and the IRA, and increasing electrification, as well as EGU-specific factors related to its age and/or operating characteristics. As described in the *Power Sector Trends* TSD, coal-fired EGUs tend to become less efficient as they age, which may impact utilities' investment decisions and the utilization of these EGUs. In addition, affected EGUs in this subcategory are unlikely to be earning the IRC section 45Q tax credit, meaning they lack an incentive to maximize both utilization and control of emissions beyond what is required by the subcategory.

The accuracy of this estimate of utilization is critical to maintaining the environmental integrity established by unit-specific, rate-based compliance under these emission guidelines. If a state assumes a level of utilization that is higher than an affected EGU actually operates during the compliance period, the resulting mass limit will be non-binding, *i.e.,* may not reflect any emission reductions relative to what the unit would have emitted in the absence of these emission guidelines. In this case a backstop emission rate helps, but the unit would become subject to a de facto less-stringent standard of performance. This result does not preserve environmental integrity consistent with CAA section 111(a)(1). Conversely, assuming a level of utilization for the purpose of setting a mass limit that is lower than an affected EGU actually operates during the compliance period maintains the level of emission reduction of unit-specific, rate-based implementation but may have unintended effects on operational flexibility. Thus, the EPA believes that in many, if not most circumstances it will not be possible for states to accurately predict the future utilization of medium-term affected EGUs.

Second, the EPA notes that the relatively lower stringency of the subcategory further complicates the calculation of an appropriate mass limit. Under mass-based compliance, the quantity of emission reductions that corresponds to a 16 percent reduction in CO_2 emission rate is a relatively small reduction in terms of tons of CO_2. This relatively small reduction is likely to be subsumed by the uncertainty inherent in predicting the utilization of an affected EGU for purposes of determining its mass limit. That is, an EGU in the medium-term subcategory that assumes future utilization consistent with its historical baseline but reduces its emission rate by 16 percent would achieve, on paper at least, an emission reduction of 16 percent. However, if its utilization during the compliance period is more than 16 percent lower than it was in the past, the EGU using a mass-based compliance approach would face a reduced or completely eliminated obligation to improve its emission performance. In this case, mass-based compliance results in a lower level of emission reduction than unit-specific rate-based compliance. While this phenomenon is not likely to occur for long-term coal-fired affected EGUs given the much higher degree of stringency of the rate-based emission limitation and the greater certainty in future utilization, the EPA believes it would be widespread amongst medium-term affected EGUs.

Thus, the EPA is not providing a presumptively approvable approach for unit-specific mass-based compliance for affected EGUs in the medium-term coal-fired subcategory. However, it is also not prohibiting states from, in their discretion, allowing the use of unit-specific mass-based compliance. For such use to be approvable in state plans it must meet two requirements. First, as previously noted in section X.D.1 of this preamble, the state must apply a backstop rate in conjunction with a mass limit for the purposes of demonstrating compliance. As a starting point, states could consider basing their backstop rate for medium-term affected EGUs on the percentage reduction from the degree of emission limitation used for the presumptively approvable backstop rate for the long-term coal-fired subcategory, *i.e.,* the 80 percent reduction relative to baseline emission performance is approximately 90.5 percent of the 88.4 percent degree of emission limitation. Applying that to the degree of emission limitation for the medium-term coal-fired subcategory is 14.5 percent, so the backstop rate, expressed in lb CO_2 per MWh on a gross basis, could be set as a 14.5 percent reduction relative to baseline emission performance on an annual calendar-year basis. Second, as described in section X.D.1 of this preamble, states must demonstrate that their plan would achieve an equivalent level of emission reduction as the application of unit-specific, rate-based standards of performance, including showing how the mass limit has been calculated and the basis for any assumptions made (*e.g.,* about utilization). As explained in this section, the EPA believes it will be very difficult for states to accurately predict the future utilization of these units, which substantially increases the risk of establishing a mass limit that

does not ensure at least an equivalent level of emission reduction. The EPA will therefore apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs employing this flexibility in state plans. Only state plans that demonstrate that use of compliance flexibilities will not erode the emission reductions required under these emission guidelines are approvable.

Comment: Commenters were generally supportive of the use of mass-based compliance mechanisms (both unit-specific and aggregate mechanisms such as emission trading) for these emission guidelines. Commenters said that mass-based compliance can help ensure environmental outcomes while also allowing sources to cycle, incorporate variable resources, and respond to grid conditions.

Response: The EPA is finalizing that mass-based compliance mechanisms are permissible when they assure an equivalent level of emission reduction with each source individually achieving its standard of performance, subject to the parameters described by the EPA in this preamble. For unit-specific mass-based compliance, affected EGUs in the medium- and long-term coal-fired subcategories may demonstrate compliance with their standards of performance through a mass limit. The EPA believes unit-specific mass-based compliance may offer some additional operational flexibility to states and affected EGUs, which could include allowing for cycling and incorporating variable resources. The EPA notes that sources must still be in compliance with the requisite backstop rate.

Comment: Many commenters expressed support for mass-based compliance mechanisms on the grounds that it facilitates calibration with existing state programs affecting the same sources that are affected under these emission guidelines.

Response: The EPA acknowledges that states may find it more straightforward to compare emission reduction obligations under these emission guidelines and existing state programs by using mass-based compliance mechanisms for state plans under these emission guidelines. However, the EPA notes that mass-based compliance mechanisms, including unit-specific mass-based compliance, are only available to certain sources affected by these emission guidelines, as described in this section of the preamble, which may be a smaller universe of sources than are affected by existing state programs. State plans must ensure an equivalent level of emission reduction from the sources that are affected sources under these emission guidelines. That is, states cannot rely on or account for emission reductions occurring at non-affected sources.

Section X.D.8 of this preamble discusses more considerations related to the relationship between the inclusion of compliance flexibilities in state plans under these emission guidelines and existing state programs.

Comment: Many commenters requested presumptively approvable mass-based standards of performance.

Response: As discussed above, the EPA is finalizing a presumptively approvable unit-specific mass-based compliance approach for units in the long-term coal-fired subcategory that includes a backstop rate to ensure an equivalent level of emission reduction. The EPA emphasizes that states should take into account the discussions of stringency in section X.B and of demonstrating equivalence in section X.D.1 of this document, as well as guidance in each subsection on particular compliance flexibilities in considering mass-based compliance approaches that deviate from the presumptively approvable method or for sources for which the EPA is not providing a presumptively approvable approach.

5. Mass-Based Emission Trading

The EPA proposed that states would be permitted to incorporate mass-based trading into their state plans under these emission guidelines. While several commenters supported the use of mass-based emission trading, as with unit-specific mass-based compliance, the EPA has significant concerns about states' ability using this mechanism to maintain an equivalent level of emission reduction to unit-specific, rate-based standards of performance. A description of and responses to comments on mass-based trading can be found at the end of this subsection.

Under these final emission guidelines, the EPA is allowing states to include mass-based emission trading for affected coal-fired EGUs in the medium- and long-term subcategories in their plans. The same requirements and caveats discussed in section X.D.4 of this preamble above apply to the respective subcategories as for unit-specific mass-based compliance. Specifically, the EPA is requiring the use of a unit-specific backstop rate in conjunction with the mass-based compliance demonstration, which is necessary for consistency with the purpose of these emission guidelines to achieve the emission reductions required under CAA section 111(a)(1) through cleaner emission performance. The Agency similarly believes it will be very difficult for states to design mass-based trading programs that include affected EGUs in the medium-term coal-fired subcategory and that maintain the level of emission reduction that would be achieved under unit-specific compliance with the presumptive standards of performance.

In general, a mass-based trading program establishes a budget of allowable mass emissions for a group of affected EGUs, with tradable instruments (typically referred to as ''allowances'') issued to affected EGUs in the amount equivalent to the mass emission budget. To establish a mass budget under these emission guidelines, states would use the rate-based standard of performance and an assumed level of utilization for each participating affected EGU, and sum the resulting individual mass limits to an aggregate mass budget. Additionally, states would need to specify in the plan how allowances would be distributed to participating affected EGUs. Each allowance would represent a tradable permit to emit one ton of CO_2, with affected EGUs required to surrender allowances at the end of the compliance period in a number determined by their reported CO_2 emissions. Total emissions from all participating affected EGUs should be no greater than the total mass budget. In addition, each participating affected EGU would need to demonstrate compliance with the unit-specific backstop rate.

The EPA sees similar potential benefits related to operational flexibility of mass-based emission trading as with unit-specific mass-based compliance, discussed in section X.D.4 of this preamble. These benefits could be heightened by having a larger pool of allowances available to affected EGUs. In addition, the EPA notes that emission trading can provide incentive for overperformance.

While there is indeed the potential for heightened benefits from mass-based emission trading due to a larger pool of allowances resulting from the inclusion of multiple sources, the EPA believes that there is also a heightened risk that the mass budget will not be appropriately calculated due to the compounding uncertainty resulting from multiple participating sources. As noted in section X.D.4 of this preamble, projecting the utilization of affected EGUs has become increasingly challenging, driven by changes in technology, fuel prices, and electricity demand. In generating a mass budget, assumptions about utilization must be made for each participating source, which magnifies the risk, particularly

for affected EGUs in the medium-term coal-fired subcategory, that an improper assumption about utilization for one affected EGU implicates the compliance obligation of other affected EGUs. Based on the understanding that a trading program that ensures the level of emission reduction of unit-specific, rate-based compliance under these emission guidelines would necessarily have to be designed with highly conservative utilization assumptions, the EPA is not providing a presumptively approvable approach for mass-based trading. The EPA additionally does not believe a presumptively approvable mass-based trading approach is warranted because, as noted in the introduction to this section, there are fewer sources covered by the final emission guidelines than the proposed emission guidelines, which may limit interest in and the utility of the use of mass-based trading for these emission guidelines.

The EPA is not prohibiting states from developing their own approaches to mass-based trading under these emission guidelines; however, they must apply a unit-specific backstop rate for all participating affected EGUs (see section X.D.4 of this preamble for a discussion of the backstop rate under unit-specific mass-based compliance), and they must demonstrate, as described in section X.D.1 of this preamble, that their plan would achieve an equivalent level of emission reduction as the application of individual rate-based standards of performance, including showing how the mass limit has been calculated and the basis for any assumptions made (*e.g.,* about utilization). As with unit-specific mass-based compliance, the EPA will apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs participating in a mass-based trading program in state plans. States must also specify the structure and purpose of any other trading program design feature(s) (*e.g.,* mass budget adjustment mechanism) and how they impact the demonstration of an equivalent level of emission reduction.

Comment: Many commenters supported the use of mass-based trading under these emission guidelines. Commenters stated that because many states are familiar with the mechanism, having used it for other pollutants in this sector or, in the case of some existing state programs, for CO_2, it would be easy to employ in the context of these emission guidelines and provide needed flexibility. In addition, commenters cited ensuring reliability as a motivation for using mass-based trading.

Response: While the EPA is finalizing that mass-based trading is permissible under these emission guidelines for affected EGUs in the medium- and long-term coal-fired subcategories, the EPA believes that some of the flexibility desired by commenters is addressed by other features of and changes made to the final emission guidelines, as described in the beginning of section X.D of this preamble. Despite familiarity on the part of states and sources with mass-based trading programs, the EPA is concerned that the unique circumstances of the EGUs affected by these final emission guidelines, including uncertainty over their future utilization as well as the relatively lower stringency of the medium-term coal-fired subcategory, pose a challenge for states in demonstrating an equivalent level of emission reduction of mass-based trading programs to the application of individual rate-based standards.

Comment: Some commenters expressed concern with whether and how mass-based trading would achieve and sustain the emission performance identified in the determination of BSER.

Response: The EPA shares these concerns, and for that reason is requiring the use of a unit-specific backstop rate in conjunction with mass-based compliance flexibilities, including mass-based trading. The EPA has also described its concerns over states' ability to estimate future utilization and will thus apply a high degree of scrutiny to assumptions made about the utilization of affected EGUs participating in mass-based trading in state plans.

6. General Emission Trading and Averaging Program Implementation Features

As noted in the proposed emission guidelines, states would need to establish the procedures and systems necessary to implement and enforce an emission averaging or trading program, whether it is rate-based or mass-based, if they elect to incorporate such flexibilities into their state plans. This would include, but is not limited to, establishing the mechanics for demonstrating compliance under the program (*e.g.,* surrender of compliance instruments as necessary based on monitoring and reporting of CO_2 emissions and generation); establishing requirements for continuous monitoring and reporting of CO_2 emissions and generation; and developing a tracking system for tradable compliance instruments. The EPA requested comment on whether there was interest in capitalizing on the existing trading program infrastructure developed by the EPA for other trading programs, and some states and one utility expressed support for states' ability to use EPA's allowance management system for such programs. In addition to providing such resources for regional and national emission trading and averaging programs, the EPA has also provided technical support and resources to various non-EPA state and regional emission trading programs. In the event states choose to create emission averaging or trading programs under these emission guidelines, the EPA can provide technical support for such programs, including through the use of the Agency's existing trading program infrastructure, and is available to consult with states during the plan development process about the appropriateness of using such resources, such as the EPA's allowance management system, based on the design of state programs.

States may also need to consider how to handle differing compliance dates for affected EGUs in an emission averaging or trading program, given that under these emission guidelines the date when standards of performance apply varies depending on the subcategory for the affected EGU. The most straightforward way to address this, and which commenters supported, is to initially only include those sources with a compliance date of January 1, 2030, and then subsequently add sources into the program (and thus factor them into the aggregate standard of performance that must be achieved in the case of rate-based averaging or mass-based budget in the case of mass-based compliance approaches) at the start of the first year in which their standard of performance applies.

Another topic that states incorporating emission averaging or trading would need to consider is whether to provide for banking of tradable compliance instruments (hereafter referred to as ''allowance banking,'' although it is relevant for both mass-based and rate-based trading programs). Allowance banking has potential implications for a trading program's ability to maintain the requisite level of emission reduction of the standards of performance. The EPA recognizes that allowance banking—that is, permitting allowances that remain unused in one control period to be carried over for use in future control periods—may provide incentives for earlier emission reductions, promote operational flexibility and planning, and facilitate market liquidity. Many commenters supported allowing banking for these reasons. However, the

EPA has observed that unrestricted allowance banking from one control period to the next (absent provisions that adjust future control period budgets to account for banked allowances) may result in a long-term allowance surplus that has the potential to undermine a trading program's ability to ensure that, at any point in time, the affected sources are achieving the required level of emission performance. In the Good Neighbor Plan's trading program provisions, for example, the EPA implemented an annual allowance bank recalibration to prevent allowance surpluses from accumulating and adversely impacting program stringency.[949] While the requirement to include a backstop rate for mass-based compliance flexibilities can mitigate some concerns that unrestricted allowance banking will undermine the program's calibration towards achieving emission reductions through cleaner performance, the EPA urges that states considering allowing trading also consider restricting allowance banking (whether all or only a portion) in order to ensure that a program continues to be calibrated towards equivalent stringency with individual rate-based standards of performance, which several commenters did support.

Comment: Many commenters expressed the need for expanding the state plan submission timeline beyond 24 months to allow more time to design emission trading and averaging programs.

Response: As discussed in section X.E.2 of this preamble, the EPA is finalizing a 24-month state plan development timeframe. Because there are significantly fewer sources covered under the final emission guidelines and because the EPA is restricting certain subcategories from using compliance flexibilities such as emission averaging and trading and unit-specific mass-based compliance, the EPA believes 24 months is a reasonable amount of time to develop state plans, including time necessary to develop compliance flexibility approaches. Moreover, the EPA is offering a presumptively approvable approach to unit-specific mass-based compliance for affected EGUs in the long-term coal-fired subcategory, which can further simplify the process for developing compliance approaches in state plans.

7. Interstate Emission Trading

In the proposed emission guidelines, the EPA requested comment on whether, and under what circumstances or conditions, to allow interstate emission trading under these emission guidelines. Given the interconnectedness of the power sector and given that many utilities and power generators operate in multiple states, interstate emission trading may increase compliance flexibility. The EPA also took comment on whether the scope of rate-based averaging should be limited to a certain level of geographic aggregation (*i.e.,* intrastate but not interstate).

Many commenters expressed support for interstate trading and averaging, arguing that it further augments the flexibility offered by these mechanisms. Because electricity markets are often operated on an interstate basis, commenters stated that interstate trading and averaging would facilitate better electricity market planning. In particular, some commenters noted that interstate programs would also allow for better grid reliability planning across areas with regional planning entities.

While the EPA is finalizing a determination that states can incorporate both rate- and mass-based interstate emission trading programs into their state plans, the EPA has significant stringency-related and logistical concerns about the use of interstate emission trading for these particular emission guidelines. For mass-based trading in particular, the EPA has concerns that further increasing the number of sources participating in the program heightens the risk that the mass budget will not be appropriately calculated due to the uncertainty in estimating future utilization of affected EGUs, thus inhibiting the ability of states to demonstrate that their program achieves an equivalent level of emission reduction. This concern is somewhat alleviated for rate-based compliance flexibilities, but the EPA notes that states that wish to implement such flexibilities on an interstate basis should do so through rate-based trading, as discussed in section X.D.2. Interstate trading programs must adhere to the same requirements described in section X.D.1 and must demonstrate equivalence of the program for all participating affected EGUs.

For interstate emission trading programs to function successfully, all participating states would need to, at a minimum, use the same form of trading and have consistent design elements and identical trading program requirements. Each state participating in an interstate trading program would need to submit their own individual state plan, subject to the state plan component and submission requirements described in section X.E, but the states would coordinate their individual plan provisions addressing the interstate trading program. Additionally, each state plan would need provisions to ensure that affected EGUs within their state are in compliance taking into account the actions of affected EGUs participating in the interstate trading program in other states. The EPA would need all state plan submissions that incorporate interstate emission trading before evaluating any of the individual state plans in order to ensure consistency among all participating states. The EPA is willing to provide technical assistance to states during the state plan development process about the use of interstate emission trading, but notes that states may need to coordinate their individual state plan submissions among different EPA regions.

8. Relationship to Existing State Programs

As described in the proposed emission guidelines, the EPA recognizes that many states have adopted policies and programs (with both a supply-side and demand-side focus) under their own authorities that have significantly reduced CO_2 emissions from EGUs, that these policies will continue to achieve future emission reductions, and that states may continue to adopt new power sector policies addressing CO_2 emissions. States have exercised their power sector authorities for a variety of purposes, including economic development, energy supply and resilience goals, conventional and GHG pollution reduction, and generating allowance proceeds for investments in communities disproportionately impacted by environmental harms. The scope and approach of the EPA's final emission guidelines differ significantly from the range of policies and programs employed by states to reduce power sector CO_2 emissions, and these emission guidelines operate more narrowly to improve the CO_2 emission performance of a subset of EGUs within the broader electric power sector.

Several commenters requested guidance on how states can count existing state programs, many of which include requirements to reduce CO_2 emissions at sources not affected by this

[949] Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards, 88 FR 36654 (June 5, 2023). Under the allowance bank recalibration provisions, EPA will recalibrate the ''Group 3'' allowance bank for the 2024–2029 control periods to meet the target bank level of 21 percent of the sum of the state emission budgets for that control period. For control periods 2030 and later, the target bank level is 10.5 percent of the sum of the state emission budgets. If the overall bank is less than the target bank level for a given control period, then no bank recalibration will occur for that control period.

rule, in their state plans under these emission guidelines. The EPA is not providing such guidance in this action but would be open to consulting with states during the state plan development process about the requirements of these emission guidelines in relation to existing state programs. States may make determinations about whether and how to design their plans, accounting for state-specific programs or requirements that apply to the same affected EGUs included in a state plan. However, as noted in section X.B, emission reductions from sources not affected by this rule cannot be used to demonstrate compliance with a standard of performance established to meet the emission guidelines. Only emission reductions at affected EGUs may count towards compliance with the state plan, including towards demonstrating compliance with the equivalent stringency criterion applied to compliance flexibilities. States may employ compliance flexibilities (such as mass-based mechanisms) described in this section in order to facilitate comparison between the requirements under existing state programs and under these emission guidelines; however, the EPA emphasizes that individual affected EGUs or groups of affected EGUs must comply with the requirements established for such units in the state plan, and that such compliance cannot incorporate measures taken by EGUs not affected by these emission guidelines.

E. State Plan Components and Submission

This section describes the requirements for the contents of state plans and the timing of state plan submissions as well as the EPA's review of and action on state plan submissions. This section also discusses issues related to the applicability of a Federal plan and timing for the promulgation of any Federal Plan, if necessary.

As explained earlier in this preamble, the requirements of 40 CFR part 60, subpart Ba, govern state plan submissions under these emission guidelines. Where the EPA is finalizing requirements that add to, supersede, or otherwise vary from the requirements of subpart Ba for the purposes of state plan submissions under these particular emission guidelines,[950] those requirements are addressed explicitly in section X.E.1.b on specific state plan requirements and in other parts of section X of this preamble. Unless expressly amended or superseded in these final emission guidelines, the provisions of subpart Ba apply.

1. Components of a State Plan Submission

A state plan must include a number of discrete components, including but not limited to those that apply for all state plans pursuant to 40 CFR part 60, subpart Ba. In this action, the EPA is also finalizing additional plan components that are specific to state plans submitted pursuant to these emission guidelines. For example, the EPA is finalizing plan components that are necessary to implement and enforce the specific types of standards of performance for affected EGUs that would be adopted by a state and incorporated into its state plan.

a. General Components

The CAA section 111 implementing regulations at 40 CFR part 60, subpart Ba, provide separate lists of administrative and technical criteria that must be met in order for a state plan submission to be deemed complete.[951] The complete list of applicable administrative completeness criteria for state plan submissions is: (1) A formal letter of submittal from the Governor or the Governor's designee requesting EPA approval of the plan or revision thereof; (2) Evidence that the state has adopted the plan in the state code or body of regulations; or issued the permit, order, or consent agreement (hereafter ''document'') in final form. That evidence must include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date; (3) Evidence that the state has the necessary legal authority under state law to adopt and implement the plan; (4) A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan, including indication of the changes made (such as redline/strikethrough) to the existing approved plan, where applicable. The submittal must be a copy of the official state regulation or document signed, stamped, and dated by the appropriate state official indicating that it is fully enforceable by the state. The effective date of the regulation or document must, whenever possible, be indicated in the document itself. The state's electronic copy must be an exact duplicate of the hard copy. If the regulation/document provided by the state for approval and incorporation by reference into the plan is a copy of an existing publication, the state submission should, whenever possible, include a copy of the publication cover page and table of contents; (5) Evidence that the state followed all applicable procedural requirements of the state's regulations, laws, and constitution in conducting and completing the adoption/issuance of the plan; (6) Evidence that public notice was given of the plan or plan revisions with procedures consistent with the requirements of 40 CFR 60.23a, including the date of publication of such notice; (7) Certification that public hearing(s) were held in accordance with the information provided in the public notice and the state's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 60.23a; (8) Compilation of public comments and the state's response thereto; and (9) Documentation of meaningful engagement, including a list of pertinent stakeholders, a summary of the engagement conducted, a summary of stakeholder input received, and a description of how stakeholder input was considered in the development of the plan or plan revisions.

Pursuant to subpart Ba, the technical criteria that all plans must meet include the following: (1) Description of the plan approach and geographic scope; (2) Identification of each designated facility (*i.e.,* affected EGU); identification of standards of performance for each affected EGU; and monitoring, recordkeeping, and reporting requirements that will determine compliance by each designated facility; (3) Identification of compliance schedules and/or increments of progress; (4) Demonstration that the state plan submission is projected to achieve emission performance under the applicable emission guidelines; (5) Documentation of state recordkeeping and reporting requirements to determine the performance of the plan as a whole; and (6) Demonstration that each standard is quantifiable, permanent, verifiable, enforceable, and nonduplicative.

b. Specific State Plan Requirements for These Emission Guidelines

To ensure that state plans submitted pursuant to these emission guidelines are consistent with the statutory requirements and the requirements of subpart Ba, the EPA is finalizing additional regulatory requirements that state plans must meet for all affected EGUs subject to a standard of performance, as well as certain subcategory-specific requirements. The EPA reiterates that standards of performance for affected EGUs included in a state plan must be quantifiable,

[950] 40 CFR 60.20a(a)(1).

[951] 40 CFR 60.27a(g)(2) and (3).

verifiable, permanent, enforceable, and non-duplicative. Additionally, per CAA section 302(l), standards of performance must be continuous in nature. Additional state plan requirements finalized as part of this action include:

- Identification of each affected EGU and the subcategory to which each affected EGU is assigned;
- A requirement that state plans include, in the regulatory portion of the plan, a list of coal-fired steam-generating EGUs that are existing sources at the time of state plan submission and that plan to permanently cease operation before January 1, 2032, and the calendar dates by which they have committed to do so. The state plan must provide that an EGU operating past the date listed in the plan is no longer exempt from these emission guidelines and is in violation of that plan, except to the extent the existing coal-fired steam generating EGU has received a time-limited extension of its date for ceasing operation pursuant to the reliability assurance mechanism described in section XII.F.3.b of this preamble;
- Standards of performance for each affected EGU, including provisions for implementation and enforcement of such standards as well as identification of the control technology or other system of emission reduction affected EGUs intend to implement to achieve the standards of performance. Standards of performance must be expressed in lb CO_2/MWh gross basis or, for affected EGUs in the low load natural gas- and oil-fired subcategory, lb CO_2/MMBtu, or, if a state is allowing the use of mass-based compliance, tons CO_2 per year;
- For each affected EGU, identification of baseline emission performance, including CO_2 mass and electricity generation data or, for affected EGUs in either the low load natural gas-fired subcategory or the low load oil-fired subcategory, heat input data from 40 CFR part 75 reporting for the 5-year period immediately prior to the date this final rule is published in the **Federal Register** and what continuous 8-quarter period from the 5-year period was used to calculate baseline emission performance;
- Where a state plan provides for the use of a compliance flexibility, such as an alternative form of the standard (*e.g.,* mass limit; aggregate emission rate limitation) and/or the use of emission averaging or trading, identification of the presumptive unit-specific rate-based standard of performance in lb CO_2/MWh-gross that would apply for each affected EGU in the absence of the compliance flexibility mechanism; the standard of performance (aggregate emission rate limitation, mass limit, or mass budget) that is actually applied for affected EGUs under the compliance flexibility mechanism and how it is calculated; provisions for the implementation and enforcement of the compliance flexibility mechanism, which includes provisions that address assurance of achievement of equivalent emission reduction, including, for mass-based compliance flexibilities, identification of the unit-specific backstop emission limitation; and a demonstration that the state plan will achieve an equivalent level of emission reduction with individual rate-based standards of performance through incorporation of the compliance flexibility mechanism;
- Increments of progress and reporting obligations and milestones as required for affected EGUs within the applicable subcategories or pursuant to consideration of RULOF, included as enforceable elements of a state plan;
- For affected EGUs in the medium-term coal-fired steam generating EGU subcategory and affected EGUs relying on a plan to permanently cease operation for application of a less stringent standard of performance pursuant to RULOF, the state plan must include an enforceable commitment to permanently cease operation by a date certain. The state plan must clearly identify the calendar dates by which such affected EGUs have committed to permanently cease operation; [952]
- A requirement that state plans provide that any existing coal-fired steam generating EGU shall operate only subject to a standard of performance pursuant to these emission guidelines or under an exemption from applicability provided under 40 CFR 60.5850b (including any time-limited extension of the date by which an EGU has committed to permanently cease operations pursuant to the reliability assurance mechanism); and
- Monitoring, reporting, and recordkeeping requirements for affected EGUs.

These final emission guidelines include requirements pertaining to the methodologies for establishing a presumptively approvable standard of performance for an affected EGU within a given subcategory. These presumptive methodologies are specified for each of the subcategories of affected EGUs in section X.C.1 of this preamble.

As discussed in sections X.C and X.D of this preamble, in order for the EPA to find a state plan ''satisfactory,'' that plan must demonstrate that it achieves the level of emission reduction that would result if each affected source was individually achieving its presumptive standard of performance, after accounting for any application of RULOF. That is, while states have the discretion to establish the applicable standards of performance for affected sources in their state plans (including whether to allow compliance to be demonstrated through the use of compliance flexibilities), the structure and purpose of CAA section 111 require that those plans achieve an equivalent level of emission reduction as applying the EPA's presumptive standards of performance to those sources (again, after accounting for any application of RULOF).

Thus, state plans must adequately document and support the process and underlying data used to establish standards of performance pursuant to these emission guidelines. Providing such documentation is critical to the EPA's review of state plans to determine whether they are satisfactory. In particular, states must include in their plan submissions information and data related to affected EGUs' emissions and operations, including CO_2 mass emissions and corresponding electricity generation data or, for affected EGUs in either the low load natural gas-fired subcategory or the oil-fired subcategory, heat input data, from 40 CFR part 75 reporting for the 5-year period immediately prior to the date the final rule is published in the **Federal Register** and identify the period from which states and affected EGUs select 8 continuous quarters of data to determine unit-specific baselines. States must include data and documentation sufficient for the EPA to understand and replicate their calculations in applying the applicable degree of emission

[952] Consistent with CAA section 111(d)(1), state plans must include commitments to cease operation as necessary for the implementation and enforcement of standards of performance. When such commitments are the predicate for receiving a particular standard of performance, adherence to those commitments is necessary to maintain the level of emission reduction Congress required under CAA section 111(a)(1). See 40 CFR 60.24a(g) (operating conditions within the control of a designated facility that are relied on for purposes of RULOF must be included as enforceable requirements in state plans); see also, *e.g.,* ''Affordable Clean Energy Rule,'' 84 FR 32520, 32558 (July 8, 2019) (repealed on other grounds) (requiring that retirement dates associated with standards of performance be included in state plans and become federally enforceable upon approval by the EPA); 76 FR 12651, 12660–63 (March 8, 2011) (best available retrofit technology requirements based on enforceable retirements that were made federally enforceable in state implementation plan); Guidance for Regional Haze State Implementation Plans for the Second Implementation Period at 34, EPA–457/B–19–003, August 2019 (to the extent a state replies on an enforceable shutdown date for a reasonable progress determination, that measure would need to be included in the SIP and/or be federally enforceable).

limitation to individual affected EGUs to establish their standards of performance. They must also provide any methods, assumptions, and calculations necessary for the EPA to review plans containing compliance flexibilities and to determine whether they achieve an equivalent (or better) level of emission reduction as unit-specific implementation of rate-based standards of performance. Plans must also adequately document and demonstrate the methods employed to implement and enforce the standards of performance such that the EPA can review and identify measures that assure transparent and verifiable implementation.

i. Requirements Related to Meaningful Engagement

Public engagement is a cornerstone of CAA section 111(d) state plan development. In November 2023, the EPA finalized requirements in the CAA section 111(d) implementing regulations at 40 CFR part 60 subpart Ba to ensure that that all affected members of the public, not just a particular subset, have an opportunity to participate in the state plan development process. These requirements are intended to ensure that the perspectives, priorities, and concerns of affected communities, including communities that are most affected by and vulnerable to emissions from affected EGUs as well as energy communities and energy workers that are affected by EGU operation and construction of pollution controls, are included in the process of establishing and implementing standards of performance for existing EGUs, including decisions about compliance strategies and compliance flexibilities that may be included in a state plan. The final requirements for meaningful engagement in subpart Ba are in addition to the preexisting public notice requirements under subpart Ba that apply to state plan development. This section describes the meaningful engagement requirements finalized separately in subpart Ba and provides guidance to states in the application of these requirements to the development of state plans under these emission guidelines.

The fundamental purpose of CAA section 111 is to reduce emissions from categories of stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, a key consideration in the state's development of a state plan is the potential impact of the proposed plan requirements on public health and welfare. Meaningful engagement is a corollary to the longstanding requirement for public participation, including through public hearings, in the course of state plan development under CAA section 111(d).[953] A robust and meaningful engagement process is critical to ensuring that the entire public has an opportunity to participate in the state plan development process and that states understand and consider the full range of impacts of a proposed plan on public health and welfare.

The EPA finalized the following definition of meaningful engagement in the final subpart Ba revisions in November 2023: ''timely engagement with pertinent stakeholders and/or their representatives in the plan development or plan revision process.'' [954] Furthermore, the definition provides that ''[s]uch engagement should not be disproportionate in favor of certain stakeholders and should be informed by available best practices.'' [955] The regulations also define pertinent stakeholders, which ''include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision.'' [956] The preamble for the final revisions to subpart Ba notes that ''[i]ncreased vulnerability of communities may be attributable to, among other reasons, an accumulation of negative environmental, health, economic, or social conditions within these populations or communities, and a lack of positive conditions.'' [957] Consistent with the requirements of subpart Ba, it is important for states to recognize and engage the communities most affected by and/or vulnerable to the impacts of a state plan, particularly as these communities may not have had a voice when the affected EGUs were originally constructed.

Most commenters were generally supportive of the requirement to conduct meaningful engagement. Commenters acknowledged that some states and utilities have already started to conduct meaningful engagement with stakeholders like that which is required by the final subpart Ba revisions in other policy contexts. Some commenters requested more time in the state plan development process specifically to facilitate conducting meaningful engagement (comments related to the state plan development timeline are addressed section X.E.2).

In the proposed emission guidelines, the EPA provided some information to assist states in identifying potential pertinent stakeholders. Some commenters sought more guidance from the EPA on how to identify pertinent stakeholders. The Agency is providing the following discussion of the potential impacts of the emission guidelines to assist states in identifying their pertinent stakeholders. The EPA believes that this discussion provides a starting point and expects that states will use their more targeted knowledge of state- and source-specific circumstances to hone the identification of pertinent stakeholders and conduct the necessary meaningful engagement. As acknowledged by the EPA in the final revisions to subpart Ba, ''states are highly diverse in, among other things, their local conditions, resources, and established practices of engagement,'' [958] so the EPA is not finalizing any additional requirements regarding the states' identification of a pertinent stakeholders for the purposes of these emission guidelines. States should consider the unique circumstances of their state and the sources within their state, with the following discussion in mind, to tailor their meaningful engagement. In addition, the EPA notes that the preamble to the final subpart Ba revisions provides discussion of best practices related to meaningful engagement.[959]

The air pollutant of concern in these emission guidelines is defined as greenhouse gases, and the air pollution addressed is elevated concentrations of these gases in the atmosphere. These elevated concentrations result in warming temperatures and other changes to the climate system that are leading to serious and life-threatening environmental and human health impacts, including increased incidence of drought and flooding, damage to crops and disruption of associated food, fiber, and fuel production systems, increased incidence of pests, increased incidence of heat-induced illness, and impacts on water availability and water quality. The Agency therefore expects that states' pertinent stakeholders will include communities within the state that are most affected by and/or vulnerable to the impacts of climate change, including those exposed to more extreme drought, flooding, and other severe weather impacts, including extreme heat and cold (states should

[953] 40 CFR 60.23(c)–(g); 40 CFR 60.23a(c)–(h).

[954] 40 CFR 60.21a(k); 88 FR 80480, 80500 (November 17, 2023).

[955] *Id.*

[956] 40 CFR 60.21a(l); 88 FR 80480, 80500 (November 17, 2023).

[957] 88 FR 80480, 80500 (November 17, 2023).

[958] *Id.*

[959] *See id.* at 80502.

refer to section III of this preamble, on climate impacts, to further assist them in identifying their pertinent stakeholders that are impacted by the pollution at issue in these emission guidelines). Commenters were supportive of the notion that those impacted by climate change are pertinent stakeholders.

Additionally, the EPA expects that another set of pertinent stakeholders will be communities located near affected EGUs and those near pipelines. These communities may experience impacts associated with implementation of the state plan, including the construction and operation of infrastructure required under a state plan. Activities related to the construction and operation of new natural gas and CO_2 pipelines may impact individuals and communities both locally and at larger distances from affected EGUs but near any associated pipelines. Commenters were supportive of the notion that communities impacted by infrastructure development required by the state plan are pertinent stakeholders.

Because these emission guidelines address air pollution that becomes well mixed and is long-lived in the atmosphere, the collective impact of a state plan is not limited to the immediate vicinity of EGUs and any associated infrastructure. The EPA therefore expects that states will consider communities and populations within the state that are both most impacted by particular affected EGUs and associated pipelines as well as those that will be most affected by the overall stringency of state plans.

The EPA also expects that states will include the energy communities impacted by each affected EGU, including the energy workers employed at affected EGUs (including employment in operation and maintenance), workers who may construct and install pollution control technology, and workers employed in associated industries such as fuel extraction and delivery and CO_2 transport and storage, as pertinent stakeholders. These communities are impacted by power sector trends on an ongoing basis. The EPA acknowledges that a variety of Federal programs are available to support these communities and encourages states to consider these programs when conducting meaningful engagement and analyzing the impacts of compliance choices.[960] Commenters supported encouraging states to both consider these communities as part of meaningful engagement under these emission guidelines as well as to take advantage of Federal resources available for employment and training assistance, and highlighted a Colorado state law [961] requiring utilities to share workforce data and develop a workforce transition plan. The EPA supports such approaches to workforce data transparency and encourages states to provide such data in the course of meaningful engagement and the development of state plans.

The EPA also expects that states will include relevant balancing authorities, systems operators and reliability coordinators that have authority to maintain electric reliability in their jurisdiction as part of their constructive engagement under these requirements. These stakeholders are impacted by a state plan as they are the entities authorized to plan for electric reliability. Visibility into unit-specific compliance plans will help ensure those entities have adequate lead time to plan and address any potential reliability-related issues. Early notification and periodic follow up on unit-specific decisions, including control technology installation and voluntary cease operation choices and timeframes will greatly assist reliability planning authorities.

Several commenters noted the need for consideration of communities overburdened by existing air pollution issues, including both greenhouse gases and co-pollutants, as pertinent stakeholders in these emission guidelines. The Agency urges states to consider the cumulative burden of pollution when identifying their pertinent stakeholders for these emission guidelines, as these stakeholders may be especially vulnerable to the impacts of a state plan or plan revision due to ''an accumulation of negative environmental . . . conditions,'' as defined in the final subpart Ba revisions. Many states are already implementing policies to consider cumulative impacts in overburdened communities, including California and New Jersey. It is also important to note that the EPA is ''prioritizing cumulative impacts research to address the multiple stressors to which people and communities are exposed, and studying how combinations of stressors affect health, well-being, and quality of life at each developmental stage throughout the course of one's life.'' [962] Additionally, the EPA is in the process of developing a workplan that lays out actions the agency will take to integrate and implement cumulative impacts within the EPA's work through FY25. The EPA's commitments, as stated in the EPA's response to the OIG Report, include continuing to refine analytic techniques based on best available science, increasing the body of relevant data and knowledge, and using outcome-based metrics to measure progress, including quantifiable pollution reduction benefits in communities.[963]

The EPA recognizes that facility- and community-specific circumstances, including the exposure of overburdened communities to additional chemical and non-chemical stressors, may also exist. The meaningful engagement process is designed to allow states to identify and to enable consideration of these and other facility- and community-specific circumstances. This includes consideration of facility- and community-specific concerns with emissions control systems, including CCS. States should design meaningful engagement to elicit input from pertinent stakeholders on facility- and community-specific issues related to implementation of emissions control systems generally, as well as on any considerations for particular systems.

The EPA encourages states to consider regional implications, explore opportunities for collaboration, and to share best practices. In some cases, an affected EGU may be located near state

[960] An April 2023 report of the Federal Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization (Energy Communities IWG) summarizes how the Bipartisan Infrastructure Law, CHIPS and Science Act, and Inflation Reduction Act have greatly increased the amount of Federal funding relevant to meeting the needs of energy communities, as well as how the Energy Communities IWG has launched an online Clearinghouse of broadly available Federal funding opportunities relevant for meeting the needs and interests of energy communities, with information on how energy communities can access Federal dollars and obtain technical assistance to make sure these new funds can connect to local projects in their communities. Interagency Working Group on Coal and Power Plant Communities and Economic Revitalization. ''Revitalizing Energy Communities: Two-Year Report to the President'' (April 2023). *https://energycommunities.gov/wp-content/uploads/2023/04/IWG-Two-Year-Report-to-the-President.pdf.*

[961] Colorado Legislature, Senate Law 19–236. *https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf.*

[962] Nicolle S. Tulve, Andrew M. Geller, Scot Hagerthey, Susan H. Julius, Emma T. Lavoie, Sarah L. Mazur, Sean J. Paul, H. Christopher Frey, Challenges and opportunities for research supporting cumulative impact assessments at the United States environmental protection agency's office of research and development, The Lancet Regional Health—Americas, Volume 30, 2024, 100666, ISSN 2667–193X, *https://doi.org/10.1016/j.lana.2023.100666.*

[963] EPA Response to Draft Office of Inspector General Report, The EPA Lacks Agencywide Policies and Guidance to Address Cumulative Impacts and Disproportionate Health Effects on Communities with Environmental Justice Concerns. *https://www.epaoig.gov/sites/default/files/reports/2023-08/_epaoig_20230822-23-p-0029.pdf.*

or Tribal borders and impact communities in neighboring states or Tribal lands. Some commenters suggested that those near state or Tribal borders may be pertinent stakeholders. The EPA agrees that it could be reasonable, in cases where EGUs are located near borders, for the state to consider identifying pertinent stakeholders in the neighboring state or Tribal land and to work with the relevant air pollution control authority of that state or Tribe to conduct meaningful engagement that addresses cross-border impacts. Some commenters supported the notion that those near state or Tribal borders may be pertinent stakeholders.

The revisions to subpart Ba in November of 2023 established requirements for demonstrating how states provided meaningful engagement with pertinent stakeholders, and these requirements apply here. According to the requirements under subpart Ba, the state will be required to describe, in its plan submittal: (1) A list of the pertinent stakeholders identified by the state; (2) a summary of engagement conducted; (3) a summary of the stakeholder input received; and (4) a description of how stakeholder input was considered in the development of the plan or plan revisions. The EPA will review the state plan to ensure that it includes these required descriptions regarding meaningful public engagement as part of its completeness evaluation of a state plan submittal. If a state plan submission does not include the required elements for notice and opportunity for public participation, including the procedural requirements at 40 CFR 60.23a(i) and 60.27a(g)(2)(ix) for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or (where a plan has become complete by operation of law) to disapprove the plan.

In approaching meaningful engagement, states should first identify their pertinent stakeholders. As previously noted, the state should allow for balanced participation, including communities most vulnerable to the impacts of the plan. Next, states should develop a strategy for engagement with the identified pertinent stakeholders. This includes ensuring that information is made available in a timely and transparent manner, with adequate and accessible notice. As part of this strategy for engagement, states should also ensure that they share information and solicit input on plan development and on any accompanying assessments or analyses. In providing transparent and adequate notice of plan development, states should consider that internet notice alone may not be appropriate for all stakeholders, given lack of access to broadband infrastructure in many communities. Thus, in addition to internet notice, examples of prominent advertisement for engagement and public hearing may include notice through newspapers, libraries, schools, hospitals, travel centers, community centers, places of worship, gas stations, convenience stores, casinos, smoke shops, Tribal Assistance for Needy Families offices, Indian Health Services, clinics, and/or other community health and social services as appropriate for the emission guideline addressed. The state should also consider any geographic, linguistic, or other barriers to participation in meaningful engagement for members of the public.

The EPA notes that several EPA resources are available to assist states and stakeholders in considering options for state plans. For example, included in the docket for this rulemaking is a unit-level proximity analysis that includes information about the population within 5 kilometers and 10 kilometers of each EGU covered by this rule. This analysis includes information about air emissions from each facility, and the potential emission implications of installing CCS. Additionally, the EPA's Power Plant Environmental Justice Screening Methodology (PPSM) [964] incorporates several peer-reviewed approaches that combine air quality modeling with environmental burden and population characteristics data to identify and connect power plants to geographic areas potentially exposed to air pollution by those power plants and to quantify the relative potential for environmental justice concern in those areas. This information provides states and stakeholders with the ability to identify the census block groups that are potentially exposed to air pollution by each EGU, including air pollutants in the vicinity of each EGU as well as pollutants that can travel significant distances. Another resource available to assist states and stakeholders is the EPA's Environmental Justice Screening and Mapping Tool (EJScreen),[965] which includes information at the census block group level about existing environmental burdens as well as socioeconomic information. Other federal resources include the Energy Communities Interagency Working Group's online Clearinghouse, which lists federal funding opportunities relevant for meeting the needs and interests of energy communities, some of which may be relevant for state plan development.

In their plan submittal, states must demonstrate evidence that they conducted meaningful engagement. In addition to a list of pertinent stakeholders and a summary of the engagement conducted, states must provide a summary of the input received and a description of how the input they received was considered in plan development. The type of information states may receive from their pertinent stakeholders could include data on the population and demographics of communities located near affected EGUs and associated pipelines; identification of and data on any overburdened communities vulnerable to the impacts of the state plan; data on the energy workers affected by anticipated compliance strategies on the part of owners and operators; data on workforce needs (*e.g.,* expected number and type of jobs created, and skills required in anticipation of compliance with the state plan); and, if relevant, data on the population and demographics of communities near state and Tribal borders that may be vulnerable to the impacts of the state plan. The EPA encourages states to include such data in their demonstration of meaningful engagement in their state plan submittal.

The EPA emphasizes to states that the meaningful engagement process is intended to include community perspectives, particularly those communities that, historically, may not have had a role in the state plan development process, in the development of standards of performance, compliance strategies, and compliance flexibilities for affected EGUs by which they are impacted.

ii. Requirements for Transparency and Compliance Assurance

The EPA proposed and requested comment on several requirements designed to help states ensure timely compliance by affected EGUs with standards of performance, as well as to assist the public in tracking affected EGUs' progress towards their compliance dates.

First, the EPA requested comment on whether to require that an affected EGU's enforceable commitment for subcategory applicability (*e.g.,* a state elects to rely on an affected coal-fired steam-generating unit's commitment to permanently cease operations before January 1, 2039, to meet the applicability requirements for the medium-term subcategory), must be in

[964] *https://www.epa.gov/power-sector/power-plant-environmental-justice-screening-methodology.*

[965] *https://www.epa.gov/ejscreen.*

the form of an emission limit of 0 lb CO_2/MWh that applies on the relevant date. Such an emission limit would be included in a state regulation, permit, order, or other acceptable legal instrument and submitted to the EPA as part of a state plan. If approved, the affected EGU would have a federally enforceable emission limit of 0 lb CO_2/MWh that would become effective as of the date that the EGU permanently ceases operations. The EPA requested comment on whether such an emission limit would have any advantages or disadvantages for compliance and enforceability relative to the alternative, which is an enforceable commitment in a state plan to cease operation by a certain date.

The EPA received few comments on this topic. One commenter,[966] in particular, did not support a specific requirement that the permit or other enforceable commitment must be in the form of an emission limit of 0 lb CO_2/MWh, claiming it seems needlessly prescriptive. This commenter also encouraged the EPA to recognize delegated or SIP-approved states' enforceable permit conditions, certifications, and voiding of authorizations, as practically enforceable.

The EPA is not finalizing a requirement that states must include commitments to permanently cease operating in state plans in the form of 0 lb CO_2/MWh emission limits. The Agency is concluding that it is within the discretion of the state to create an enforceable commitment to permanently cease operation, where applicable, in the form it deems appropriate. Such commitments may be codified in a state regulation, permit, order, or other acceptable legal instrument and submitted to the EPA as part of a state plan. It is important to note that if an emission limit or some other requirement that creates an enforceable commitment to cease operation is initially included in a title V permit before the submission of a state plan, that condition must be labeled as ''state-only'' or ''state-only enforceable'' until the EPA approves the state plan, at which point the permit should be revised to make that requirement federally enforceable. Including state instruments (such as state permits, certifications, and other authorizations) reflecting affected EGUs' intent to permanently cease operation in the state plan, when such intent is the basis of receiving a less stringent standard of performance, is necessary because state instruments can be revised without a corresponding revision to the state plan or standard of performance. This outcome—a source continuing to operate into the future with a less-stringent standard of performance that is not necessarily warranted—would undermine the integrity of these emission guidelines.

Second, the EPA proposed and is finalizing a requirement that state plans that include affected EGUs that plan to permanently cease operation must require that each such affected EGU comply with applicable state and Federal requirements for permanently ceasing operation, including removal from its respective state's air emissions inventory and amending or revoking all applicable permits to reflect the permanent shutdown status of the EGU. This requirement covers affected coal-fired steam generating EGUs in the medium-term subcategory as well as affected EGUs that are relying on a commitment to permanently cease operating to obtain a less stringent standard of performance pursuant to consideration of RULOF. This requirement merely reinforces the application of requirements under state and Federal laws that are necessary in this context for transparency and the orderly administration of these emission guidelines.

Third, the EPA proposed and is finalizing a requirement that each state plan must require owners and operators of affected EGUs to establish publicly accessible websites, referred to here as a ''Carbon Pollution Standards for EGUs website,'' to which all reporting and recordkeeping information for each affected EGU subject to the state plan would be posted, including the aforementioned information required to be submitted as part of the state plan. This information includes, but is not limited to, emissions data and other information relevant to determining compliance with applicable standards of performance, information relevant to the designation and determination of compliance with increments of progress and reporting obligations including milestones for affected EGUs that plan to permanently cease operations, and any extension requests made and granted pursuant to the compliance date extension mechanism or the reliability assurance mechanism. Although this information will also be required to be submitted directly to the EPA and the relevant state regulatory authority, both the EPA and stakeholders have an interest in ensuring that the information is made accessible in a timely manner. Some commenters agreed with these requirements. The EPA anticipates that the owners or operators of some affected EGUs may already be posting comparable reporting and recordkeeping information to publicly available websites under the EPA's April 2015 Coal Combustion Residuals Rule,[967] such that the burden of this website requirement for these units could be minimal.

Comment: Several commenters argued that this was a duplicative requirement, noting that utilities already report GHG emissions data under the Acid Rain Program and Mandatory GHG Reporting Program. Commenters also stated that this requirement would pose a burden for companies who would have to dedicate staff to maintaining the website. One commenter[968] suggested that EPA include more specific requirements related to the format of data, notification of uploads and removal of documentation, and summarization of content.

Response: The EPA disagrees that this requirement is duplicative of reporting requirements under other programs. In addition to affected EGUs having unique standards of performance and compliance schedules under these emission guidelines, these emission guidelines also include unique reporting requirements that are not covered by the programs identified by the commenters, including increments of progress and reporting on milestones. In addition, the EPA believes that this information should be made broadly available to all stakeholders in a timely manner, which is not necessarily accomplished via the programs and reporting mechanisms identified by the commenters. Accordingly, the EPA is finalizing a requirement that each state plan must require owners and operators of affected EGUs to establish publicly accessible websites and to post the relevant information described in this section. Additionally, data should be available in a readily downloadable format.

Fourth, to promote transparency and to assist the EPA and the public in assessing progress towards compliance with state plan requirements, the EPA proposed and is finalizing a requirement that state plans include a requirement that the owner or operator of each affected EGU shall report any deviation from any federally enforceable state plan increment of progress or reporting milestone within 30 business days after

[966] See Document ID No. EPA–HQ–OAR–2023–0072–0781.

[967] See *https://www.epa.gov/coalash/list-publicly-accessible-internet-sites-hosting-compliance-data-and-information-required* for a list of websites for facilities posting Coal Combustion Residuals Rule compliance information, *see also* 80 FR 21301 (April 17, 2015).

[968] See Document ID No. EPA–HQ–OAR–2023–0072–0813.

the owner or operator of the affected EGU knew or should have known of the event. That is, the owner or operator must report within 30 business days if it is behind schedule such that it has missed an increment of progress or reporting milestone. In the report, the owner or operator of the affected EGU will be required to explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. The owner or operator of the EGU must submit the report to the state regulatory agency and concurrently post the report to the affected EGU's Carbon Pollution Standards for EGUs website.

Fifth, in the proposed action, the EPA explained its general approach to exercising its enforcement authorities through administrative compliance orders (''ACOs'') to ensure compliance while addressing genuine risks to electric system reliability. The EPA solicited comment on whether to promulgate requirements in the final emission guidelines pertaining to the demonstrations, analysis, and information the owner or operator of an affected EGU would have to submit to the EPA in order to be considered for an ACO. The EPA is not finalizing the proposed approach to use ACOs to address risks to grid reliability.

Comment: One commenter argued that the conditions to qualify for an ACO would make it challenging for an EGU to obtain an ACO in instances of urgent reliability.[969] Commenters argued that there are not any guarantees that the EPA would act on such requests for an ACO in a timely manner, particularly because the EPA has not set any deadline for review and presumably would argue that any decision falls within the EPA's enforcement discretion and is not subject to judicial review. Additionally, one commenter argued that the proposal is unworkable for the purposes of addressing more immediate reliability needs, specifying that EGUs may not be able to readily obtain the information or analysis necessary for preparing documentation for the EPA from their regional entity or state.[970]

Another commenter argued that the proposed mechanism provides no relief during an energy crisis because they would be offered only after the fact to resolve any alleged violations. Therefore, the possibility of future enforcement discretion and ACOs will not help a power generator decide in the moment whether to keep running and risk a violation or shut down, risking grid reliability and affecting our customers. the commenter also stated that ACOs are enforcement actions that carry negative implications and the potential for significant civil penalties, and citizen groups are unlikely to exercise discretion similar to that of the EPA, even if the EPA decides that a low (or no) penalty is appropriate. Lastly, this commenter noted that ACOs are typically intended to resolve relatively short-term noncompliance events that can be remedied and that do not reflect a fundamental inability to comply.

Response: As discussed in section XII.F and elsewhere in this preamble, the EPA has made several adjustments and provided several mechanisms in this final rule that have the effect of or are expressly intended to provide grid operators and reliability authorities methods to address grid reliability. For example, the EPA is providing that states may include in their state plans a short-term reliability mechanism that allows affected EGUs to comply with an emission limitation corresponding to their baseline emission rate during periods of grid emergency. For further detail, see section XII.F.3.a of this preamble. This mechanism is intended to allow states to respond quickly to emergency situations, and to avoid affected EGUs being out of compliance or needing to work towards compliance through an ACO. Considering the structural changes the EPA has made in these final emission guidelines and the mechanisms it is providing states to address grid reliability, the EPA does not believe that states and affected EGUs will need to rely on ACOs to address compliance during periods of grid emergency.

Finally, as explained in section VII.B of this preamble, coal-fired steam generating EGUs that plan to permanently cease operating before January 1, 2032, are not covered by these emission guidelines, *i.e.,* they are not affected EGUs. However, to maintain the environmental integrity of these emission guidelines, it is critical that any existing sources that are operating as of January 1, 2032, are doing so subject to a requirement to operate more cleanly, and therefore essential that sources report on their actions to qualify for the exemption. As explained in the preamble to the proposed rule and section X.C.4 of this preamble, there are many steps the owners or operators of EGUs must take as they get ready to permanently cease operations and those steps vary between units and jurisdictions. Procession in a timely manner through these steps is the best indicator the EPA has of whether or not an existing source remains qualified for an exemption from these emission guidelines. Should a source's plans to cease operating change, *e.g.,* because the relevant planning authority has called on it to remain in operation for reliability or resource adequacy, the state, the public, and the EPA need to be aware of that change as soon as possible in order to appropriately address the source under these emission guidelines. The EPA therefore believes that having sources that plan to cease operation before January 1, 2032, report to the Agency on the steps they have taken towards doing so is critical to ensuring that those sources remain qualified for the exemption and thus to maintaining the environmental integrity of these emission guidelines.

The EPA is requiring existing coal-fired steam generating EGUs that are in existence as of the date of a state plan submission but plan to cease operating before January 1, 2032, to comply with certain reporting requirements pursuant to CAA section 114(a). Among other things, this provision gives the EPA authority to require recordkeeping and reporting of sources for the purpose of ''developing or assisting in the development of any implementation plan under . . . section 7411(d) of this title[or] any standard of performance under section 7411 of this title,'' ''determining whether any person is in violation of any such standard of any requirement of such a plan,'' or ''carrying out any provision of this chapter.'' Owners or operators of coal-fired steam generating EGUs that would be covered by these emission guidelines but for their plans to permanently cease operating are required to make reports necessary to ascertain whether they will in fact qualify for the exemption. This reporting obligation is necessary for preserving the integrity of the rule, and is consistent with ensuring that states develop plans that include standards of performance for all existing sources and for anticipating whether a state plan may need to be revised to include a standard of performance for an existing source that will not be eligible for an exemption from these emission guidelines.[971]

[969] See Document ID No. EPA–HQ–OAR–2023–0072–0770.

[970] *Id.*

[971] The milestone reporting requirements for affected coal-fired steam generating EGUs in the medium-term subcategory and those relying on a shorter remaining useful life for a less-stringent standard of performance pursuant to RULOF are authorized under both CAA sections 114(a) and 111(d)(1), the latter of which provides that state plans shall provide for the implementation and enforcement of standards of performance. In that

The reporting requirements the EPA is promulgating for sources that plan to permanently cease operation before January 1, 2032, are similar to the reporting requirements the Agency is requiring for medium-term coal-fired steam generating affected EGUs and affected EGUs relying on a shorter remaining useful life for a less-stringent standard of performance through RULOF. Those requirements are described in section X.C.4 of this preamble and require the definition of milestones tailored to individual units which are then embedded in periodic reporting requirements to assess progress toward the cessation of operations. However, consistent with CAA section 114, the requirements for sources that are exempt from these emission guidelines are limited to reporting and do not include the establishment of milestones. Thus, the requirements are as follows: Five years before any planned date to permanently cease operations or by the date upon which state plan is submitted, whichever is later, the owner or operator of the EGU must submit an initial report to the EPA that includes the following: (1) A summary of the process steps required for the EGU to permanently cease operation by the date included in the state plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. These process steps may include, *e.g.,* initial notice to the relevant reliability authority of the deactivation date and submittal of an official retirement filing (or equivalent filing) made to the EGU's reliability authority. (2) Supporting regulatory documents, including correspondence and official filings with the relevant regional RTO, ISO, balancing authority, PUC, or other applicable authority; any deactivation-related reliability assessments conducted by the RTO or ISO; and any filings pertaining to the EGU with the SEC or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which the plans for the EGU are mentioned; any integrated resource plans and PUC orders referring to or approving the EGU's deactivation; any reliability analyses developed by the RTO, ISO, or relevant reliability authority in response to the EGU's deactivation notification; any notification from a reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and any notification to or from an RTO, ISO, or relevant reliability authority altering the timing of deactivation for the EGU.

For each of the remaining years prior to the date by which an EGU has committed to permanently cease operations, the operator or operator of an EGU must submit an annual status report to the EPA that includes: (1) Progress on each of the process steps identified in the initial report; and (2) supporting regulatory documents, including correspondence and official filings with the relevant RTO, balancing authority, PUC, or other applicable authority to demonstrate progress toward all steps; and (3) regulatory documents, and relevant SEC filings (listed in the preceding paragraph) that have been issued, filed or received since the prior report.

The EPA is also requiring that EGUs that plan to permanently cease operation by January 1, 2032, submit a final report to the EPA no later than 6 months following its committed closure date. This report would document any actions that the unit has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

2. Timing of State Plan Submissions

The EPA proposed a state plan submission deadline that is 24 months from the date of publication of the final emission guidelines, which, at that time was 9 months longer than the default state plan submission timeline in the proposed 40 CFR part 60, subpart Ba implementing regulations. The EPA finalized subpart Ba with a default timeline of 18 months for state plan submissions, 40 CFR 60.23a(a)(1); regardless, the EPA is superseding subpart Ba's timeline under these emission guidelines and is requiring that state plans be submitted 24 months after publication of this final rule in the **Federal Register**.

As discussed in the preamble to the proposed rule,[972] these emission guidelines apply to a relatively complex source category and state plan development will require significant analysis, consultation, and coordination between states, utilities, reliability authorities, and the owners or operators of individual affected EGUs. The power sector is subject to layers of regulatory and other requirements under different authorities (*e.g.,* environmental, electric reliability, SEC) and the decisions states make under these emission guidelines will necessarily have to accommodate overlapping considerations and processes. States' plan development may have to integrate decision making by not only the relevant air agency or agencies, but also ISOs, RTOs, or other balancing authorities. While 18 months is a reasonable timeframe to accommodate state plan development for source categories that do not require this level of coordination, the EPA does not believe it is reasonable to expect states and affected EGUs to undertake the coordination and planning necessary to ensure that plans for implementing these emission guidelines are consistent with the broader needs and trajectory of the power sector within the default period provided under subpart Ba.

However, there are also notable differences between the circumstances of the proposed versus these final emission guidelines that are relevant to the state plan submission timeline. First, the EPA is not finalizing emission guidelines applicable to combustion turbine EGUs, which will significantly decrease the number of affected EGUs that states must address in their plans. Relative to proposal, there are approximately 184 fewer individual units to which these emission guidelines will apply (based on information at the time of the final rule), and the final emission guidelines do not include co-firing with low-GHG hydrogen as a BSER. The analytical and other burdens associated with state planning will thus be significantly lighter than anticipated at proposal, as states will have to address not only fewer sources but also a smaller universe of potential control strategies. Additionally, as explained in section VII.B.1 of this preamble, these final emission guidelines do not apply to existing coal-fired EGUs that plan to permanently cease operation prior to January 1, 2032. While under the proposed emission guidelines states would have had to establish standards of performance for every existing source operating as of January 1, 2030, states will be able to forgo addressing a subset of these existing sources under this final rule.

In addition to states needing to address far fewer existing sources in their state plans than anticipated under the proposed emission guidelines, it is also not expected that the owners or operators of sources will begin implementation of control strategies before state plan submission. At proposal the EPA believed that some owners or operators of affected EGUs would do feasibility and FEED studies for CCS during state plan development,

case, reporting requirements are necessary to ensure that the predicate conditions for the sources' standards of performance are satisfied.

[972] 88 FR 33240, 33402–03 (May 23, 2023).

i.e., before state plan submission. For other affected coal-fired EGUs, the EPA anticipated that owners or operators would undertake certain planning, design, and permitting steps prior to state plan submission.[973] In developing these final emission guidelines, the EPA changed its earlier assumption that states and affected EGUs would take significant steps towards planning and implementing control strategies prior to state plan submission. There are certain preliminary steps, such as an initial feasibility study, that the EPA expects that states and/or affected EGUs will undertake as a typical part of the state planning process. Under any rule or circumstances, it would not be reasonable for a state to commit an affected EGU to installation and operation of a certain control technology without undertaking at least an initial assessment of that technology—this is what is accomplished by feasibility studies. However, while the Agency believes that some sources are currently or will be undertaking FEED studies or other significant steps towards implementing pollution controls independent of these emission guidelines at earlier times, the EPA is not assuming when setting the compliance deadline that EGUs will be taking such steps prior to the existence of a state law requirement to do so (*i.e.,* prior to state plan adoption and submission).

The EPA received a number of comments on the proposed 24-month timeline for state plan submissions, which are discussed in detail below. As a general matter, many of these comments requested a longer timeframe for developing and submitting state plans. However, given that the number of affected EGUs state plans will have to cover under these final emission guidelines is very likely to be significantly lower than anticipated based on the proposal and that the EPA is not expecting states or owners or operators of affected EGUs to conduct FEED studies or otherwise start work on implementation prior to state plan submission, the EPA continues to believe that 24 months is an appropriate timeframe. Additionally, as discussed in the preamble to the recent revisions to the 40 CFR part 60, subpart Ba implementing regulations, the EPA's approach to timelines for state plan submission and review under CAA section 111(d) is informed by the need to minimize the impacts of emissions of dangerous air pollutants on public health and welfare by proceeding as expeditiously and as reasonably possible while accommodating the time needed for states to develop an effective plan.[974] To this end, the EPA is promulgating a timeframe for state plan submissions that is based on the minimum administrative time that is reasonably necessary given the need for states and owners or operators of affected EGUs to coordinate with reliability authorities in the development of state plans. In this case, the EPA believes that providing an additional 6 months beyond subpart Ba's 18 months for state plan submissions is sufficient to accommodate this additional coordination, particularly given that the number of affected EGUs that states will be addressing in their plans is far fewer than expected under the proposed emission guidelines.

Comment: Several commenters supported the EPA's proposed 24-month timeframe for state plan submissions and stressed the importance of achieving emission reductions as quickly as possible. Commenters also noted that, based on anecdotal evidence, 24 months is generally sufficient to incorporate legislative, regulatory, and other administrative procedures associates with submitting state plans. Many commenters, however, requested that the EPA provide additional time for states to develop and submit their state plans; many requested 36 months with some commenters asserting that even more time would be required. Commenters asking for a longer timeframe cited reasons including the size of states' EGU fleets and the specific BSERs proposed for certain subcategories (*i.e.,* CCS and hydrogen co-firing), the need for owners or operators of affected EGUs to conduct systems analyses and update their integrated resource plans (IRPs) prior to making final decisions for state plans, and the need for states to get their choices approved by the appropriate reliability and other regulatory commissions.

Response: As explained above, the EPA has made a number of changes in these final emission guidelines that have the effect of decreasing the planning burden on states, including not finalizing requirements for combustion turbine EGUs, exempting coal-fired EGUs that plan to cease operating by January 1, 2032, finalizing fewer subcategories for coal-fired EGUs, and not finalizing the subcategory for coal-fired EGUs that was based on utilization level. In general, these changes will decrease the number of units that state plans must address and also decrease the number and complexity of decisions states must make with regard to those units. Furthermore, 24 months is sufficient time for states to complete the steps necessary to develop and submit a state plan. Owners and operators are already or should already be considering how they will operate in a future environment where sources operating more cleanly are valued more. The EPA expects that states are already working or will work closely with the operators and operators of affected EGUs as those owners and operators update their IRPs and proceed through any necessary processes with, *e.g.,* PUCs and reliability authorities. Thus, the Agency expects that consultation with and between owners and operators, PUCs, and reliability authorities is currently ongoing and will remain so throughout state plan development and implementation. Against this backdrop of ongoing planning and consultation, the EPA's obligation in these emission guidelines is to ensure that state plan development and submission occurs within a timeframe consistent with the ''adherence to [the EPA's] 2015 finding of an urgent need to counteract the threats posed by unregulated carbon dioxide emissions from coal-fired power plants.'' [975] The timeframe the EPA is providing for state plan development upfront coupled with the long lead times it is providing for compliance with standards of performance provides states and owners or operators ample time to ensure the orderly implementation of the control requirements under these emission guidelines.

Comment: Several commenters asserted that the EPA should provide longer than 24 months for state plan submissions to provide time for states to work through their necessary rulemaking, legislative, and/or administrative processes. Some commenters similarly stated that more than 24 months is needed in order to accommodate meaningful engagement on draft state plans.

Response: The default timeline provided for state plan development and submission under 40 CFR part 60, subpart Ba is 18 months. As the EPA acknowledged when it promulgated this timeframe, state regulatory and legislative processes and resources can vary significantly and influence the time needed to develop and submit state plans.[976] However, the CAA contains

[973] 88 FR 33240, 33402 (May 23, 2023).

[974] See, *e.g.,* 88 FR 80480, 80486 (November 17, 2023).

[975] *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914, 994 (D.C. Cir. 2021).

[976] 88 FR 80480, 80488 (November 17, 2023).

numerous, long-standing requirements under other programs for states to develop and submit plans in 18 or fewer months. The EPA therefore believes that states should be well positioned to accommodate an 18-month state plan submission timeframe, let alone at 24-month timeframe, from the perspective of the timing of state processes. The Agency does not believe it would be reasonable or consistent with CAA section 111's purpose of reducing air pollution that endangers public health and the environment to extend state plan submission deadlines to defer to lengthy state administrative processes.

Similarly, the EPA believes that 24 months provides sufficient time for states to conduct meaningful engagement with pertinent stakeholders under these emission guidelines. As discussed in section X.E.1.b.i of this preamble, the EPA is providing additional information in these final emission guidelines that states may use to inform their meaningful engagement strategies and that can help them to fulfill their obligations in a timely and diligent fashion. For example, the EPA has noted a number of types of stakeholder communities to assist states in identifying their pertinent stakeholders. It has also provided information and tools that states may use in considering options for state plans, including facility-specific information on air emissions and the potential emissions implications of installing CCS. Commenters also pointed out that several states have recently adopted regulations, programs, and tools relevant to identifying pertinent stakeholders and conducting meaningful engagement; such programs and tools, in addition to states' growing body of knowledge and experience pursuant to state initiatives and priorities, will aid states and stakeholders alike in conducting robust meaningful engagement in the timeframe for state plan development.

3. State Plan Revisions

As discussed in the preamble of the proposed action, the EPA expects that the 24-month state plan submission deadline for these emission guidelines would give states, utilities and independent power producers, and stakeholders sufficient time to determine into which subcategory each of the affected EGUs should fall and to formulate and submit a state plan accordingly. However, the EPA also acknowledges that, despite states' best efforts to accurately reflect the plans of owners or operators with regard to affected EGUs at the time of state plan submission, such plans may subsequently change. In general, states have the authority and discretion to submit revised state plans to the EPA for approval.[977] State plan revisions are generally subject to the same requirements as initial state plan submissions under these emission guidelines and the subpart Ba implementing regulations, including meaningful engagement, and the EPA reviews state plan revisions against the applicable requirements of these emission guidelines and the subpart Ba implementing regulations in the same manner in which it reviews initial state plan submissions pursuant to 40 CFR 60.27a. Requirements of the initial state plan approved by the EPA remain federally enforceable unless and until the EPA approves a plan revision that supersedes such requirements. States and affected EGUs should plan accordingly to avoid noncompliance.

The EPA is finalizing a state plan submission date that is 24 months after the publication of the final emission guidelines and is finalizing the first compliance date for affected coal-fired EGUs in the medium-term subcategory and affected natural gas- and oil-fired EGUs of January 1, 2030. A state may choose to submit a plan revision prior to the compliance dates in its existing state plan; however, the EPA reiterates that any already approved federally enforceable requirements, including milestones, increments of progress, and standards of performance, will remain in place unless and until the EPA approves the plan revision.

The EPA requested comment on whether it would be helpful to states to impose a cutoff date for the submission of plan revisions before the first compliance date. This would, in effect, establish a temporary moratorium on plan submissions in order to allow the EPA to act on the plans. State plan revisions would again be permitted after the final compliance date. The EPA is not finalizing such cutoff date to provide more flexibility to states in submitting revisions closer to the first compliance date, in the case that EPA may be able to review those revisions before the first compliance date.

Comment: Several commenters generally disagreed with establishing a cutoff date for state plan revisions before the first compliance date, arguing these timelines would be unworkable because state plan revisions may require public notice and stakeholder engagement.

Response: The EPA is not finalizing an explicit cutoff date that would in effect establish a temporary moratorium on plan submissions; however, the EPA notes that, because the first compliance date under the final emission guidelines is January 1, 2030, a plan revision submitted after November 1, 2028 (taking into consideration 1 year for EPA action on a state plan revision plus up to 60 days, approximately, for a completeness determination) may not provide sufficient time for the EPA to review and approve the plan sufficiently in advance of that compliance date to allow sources to appropriately plan for compliance. The EPA reiterates that EGUs will be expected to comply with any requirements already approved in the state plan until such time as the plan revision is approved.

4. Dual-Path Standards of Performance for Affected EGUs

As discussed in the proposed action, under the structure of these emission guidelines, states would assign affected coal-fired EGUs to subcategories in their state plans, and an affected EGU would not be able to change its applicable subcategory without a state plan revision. This is because, due to the nature of the BSERs for coal-fired steam generating units, an affected EGU that switches into either the medium-term or long-term subcategory may not be able to meet the compliance obligations for a new and different subcategory without considerable lead time; in order to ensure timely emission reductions, it is important that states identify which subcategories affected EGUs fall into in their state plan submissions so that affected EGUs have certainty about their expected regulatory obligations. Therefore, as a general matter, states must assign each affected EGU to a subcategory and have in place all the legal instruments necessary to implement the requirements for that subcategory by the time of state plan submission.

However, the EPA also solicited comment on a dual-path approach that would allow coal-fired steam generating units to have two different standards of performance submitted to the EPA in a state plan based on potential inclusion in two different subcategories. This proposal was based in large part on the proposed structure of the subcategories for coal-fired affected EGUs, under which it would have been realistic to expect that sources could prepare to comply with either the presumptive standard of performance for, *e.g.,* the imminent-term subcategory and the near-term subcategory or the imminent-term subcategory and the medium-term subcategory.

Because the final emission guidelines include only two subcategories for coal-

[977] 40 CFR 60.23a(a)(2), 60.28a.

fired affected EGUs and do not include the two subcategories for which the dual-path approach would have been appropriate, the EPA is not finalizing an approach that allows coal-fired steam generating units to have two different standards of performance submitted to the EPA in a state plan based on potential inclusion in two different subcategories.

Comment: In general, commenters supported a dual-path approach; however, several commenters requested that the EPA accommodate a multi-pathway approach (three or more pathways) due to the complexity of state plans and potential for numerous compliance pathways because of factors beyond the EGU owner or operator's control, such as infrastructure for CCS projects and increase in electric power demand due to electrification of the transportation sector.

Response: As stated above, the EPA is not finalizing the dual-path approach, nor a multi-pathway approach. If an affected EGU wishes to switch subcategories after the initial state plan approval, the state should submit a state plan revision sufficiently in advance of the compliance date for the subcategory into which it was assigned to permit the EPA's review and action on that plan revision.

5. EPA Action on State Plans

Pursuant to the final revisions to 40 CFR part 60, subpart Ba, in this action, the EPA is subject to a 60-day timeline for the Administrator's determination of completeness of a state plan submission and a 12-month timeline for action on state plans.[978] The timeframes and requirements for state plan submissions described in this section also apply to state plan revisions.[979]

As discussed in the proposed action, the EPA would first review the components of the state plan to determine whether the plan meets the completeness criteria of 40 CFR 60.27a(g). The EPA must determine whether a state plan submission has met the completeness criteria within 60 days of its receipt of that submission. If the EPA has failed to make a completeness determination for a state plan submission within 60 days of receipt, the submission shall be deemed, by operation of law, complete as of that date. Subpart Ba requires the EPA to take final action on a state plan submission within 12 months of that submission's being deemed complete. The EPA will review the components of state plan submissions against the applicable requirements of subpart Ba and these emission guidelines, consistent with the underlying requirement that state plans must be ''satisfactory'' ' per CAA section 111(d). The Administrator would have the option to fully approve; fully disapprove; partially approve and partially disapprove; or conditionally approve a state plan submission.[980] Any components of a state plan submission that the EPA approves become federally enforceable.

The EPA solicited comment on the use of the timeframes regarding EPA action on state plans in subpart Ba and commenters encouraged reconsidering the schedule, suggesting either increasing or decreasing the amount of time for action on state plans. In the final emission guidelines, the EPA is not superseding the timeframes in subpart Ba regarding EPA action on state plans and plan revisions.

Comment: One commenter suggested that the EPA should provide for automatic extension of compliance dates for affected EGUs if the Agency does not meet its 12-month deadline for plan approval.[981] Other commenters expressed concerns that the EPA will be unable to review all plans in the 12-month timeframe. One commenter suggested that the EPA should strive to review plans in less than the proposed 12-month timeframe.[982]

Response: The EPA does not believe it is appropriate to provide automatic extensions of compliance dates based on the timeframe for EPA action on state plan submissions. While there may be some degree of regulatory uncertainty that stems from waiting for the Agency to act on a state plan submission, it would not be a reasonable solution to add to that uncertainty by also making compliance dates contingent on the date of EPA's action. This additional uncertainty could have the effect of unnecessarily extending the compliance schedule and delaying emission reductions. Given that the dates on which the EPA takes final action on individual state plans are likely to be many and varied (based on, *inter alia,* when each state plan was submitted to the Agency), such extensions would create unnecessary confusion and potentially uneven application of the requirements for state plans. In this action, the EPA does not find a reason to supersede the timelines finalized in subpart Ba; therefore, review of and action on state plan submissions will be governed by the requirements of revised subpart Ba.

6. Federal Plan Applicability and Promulgation Timing

The provisions of 40 CFR part 60, subpart Ba, apply to the EPA's promulgation of any Federal plans under these emission guidelines. The EPA's obligation to promulgate a Federal plan is triggered in three situations: where a state does not submit a plan by the plan submission deadline; where the EPA determines that a state plan submission does not meet the completeness criteria and the time period for state plan submission has elapsed; and where the EPA fully or partially disapproves a state's plan.[983] Where a state has failed to submit a plan by the submission deadline, subpart Ba gives the EPA 12 months from the state plan submission due date to promulgate a Federal plan; otherwise, the 12-month period starts, as applicable, from the date the state plan submission is deemed incomplete or from the date of the EPA's disapproval. If the state submits and the EPA approves a state plan submission that corrects the relevant deficiency within the 12-month period, before the EPA promulgates a Federal plan, the EPA's obligation to promulgate a Federal plan is relieved.[984]

As provided by 40 CFR 60.27a(e), a Federal plan will prescribe standards of performance for affected EGUs of the same stringency as required by these emission guidelines and will require compliance with such standards as expeditiously as practicable but no later than the final compliance date under these guidelines. However, 40 CFR 60.27a(e)(2) provides that, upon application by the owner or operator of an affected EGU, the EPA may provide for the application of a less stringent standard of performance or longer compliance schedule than provided by these emission guidelines, in which case the EPA would follow the same process and criteria in the regulations that apply to states' provision of RULOF standards. Under subpart Ba, the EPA is also required to conduct meaningful engagement with pertinent stakeholders prior to promulgating a Federal plan.[985]

As discussed in section X.E.2 of this preamble, the EPA is finalizing a deadline for state plan submissions of 24 months after publication of these final emission guidelines in the **Federal Register**. Therefore, if a state fails to timely submit a state plan, the EPA

[978] 40 CFR 60.27a(b), (g)(1).

[979] See generally 40 CFR 60.27a.

[980] 40 CFR 60.27a(b).

[981] See Document ID No. EPA–HQ–OAR–2023–0072–0660.

[982] See Document ID No. EPA–HQ–OAR–2023–0072–0764.

[983] 40 CFR 60.27a(c).

[984] 40 CFR 60.27a(d).

[985] 40 CFR 60.27a(f).

would be obligated to promulgate a Federal plan within 36 months of publication of these final emission guidelines. Note that this will be the earliest possible obligation for the EPA to promulgate a Federal plan and that different triggers (*e.g.,* a disapproved state plan) will result in later obligations to promulgate Federal plans for other states, contingent on when the obligation is triggered.

Finally, the EPA acknowledges that, if a Tribe does not seek and obtain the authority from the EPA to establish a TIP, the EPA has the authority to establish a Federal CAA section 111(d) plan for areas of Indian country where designated facilities are located. A Federal plan would apply to all designated facilities located in the areas of Indian country covered by the Federal plan unless and until the EPA approves an applicable TIP applicable to those facilities.

XI. Implications for Other CAA Programs

A. New Source Review Program

The CAA's New Source Review (NSR) preconstruction permitting program applies to stationary sources that emit pollutants resulting from new construction and modifications of existing sources. The NSR program is authorized by CAA section 110(a)(2)(C), which requires that each state implementation plan (SIP) ''include a program to provide for the . . . regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that [NAAQS] are achieved, including a permit program as required in parts C and D [of title I of the CAA].'' The ''permit program as required in parts C and D'' refers to the ''major NSR'' program, which applies to new ''major stationary sources'' [986] and ''major modifications'' [987] of existing stationary sources. The ''minor NSR'' program applies to new construction and modifications of stationary sources that do not meet the emission thresholds for major NSR. NSR applicability is pollutant-specific, so a source seeking to newly construct or modify may need to obtain both major NSR and minor NSR permits before it can begin construction.

Under the CAA, states have primary responsibility for issuing NSR permits, and they can customize their programs within the limits of EPA regulations. The Federal NSR rules applying to state permitting authorities are found at 40 CFR 51.160 to 51.166. The EPA's primary role is to approve state program regulations and to review, comment on, and take any other necessary actions on draft and final permits to assure consistency with the EPA's rules, the SIP, and the CAA. When a state does not have EPA-approved authority to issue NSR permits, the EPA issues the NSR permits within the state, or delegates authority to the state to issue the NSR permits on behalf of the EPA, pursuant to rules at 40 CFR 49.151–173, 40 CFR 52.21, and 40 CFR 124.

For the major NSR program, the requirements that apply to a source depend on the air quality designation at the location of the source for each of its emitted pollutants at the time the permit is issued. Major NSR permits for sources located in an area that is designated as attainment or unclassifiable for the NAAQS for its pollutants are referred to as Prevention of Significant Deterioration (PSD) permits. PSD permits can include requirements for specific pollutants for which there are no NAAQS.[988] Sources subject to PSD must, among other requirements, comply with emission limitations that reflect the Best Available Control Technology (BACT) for ''each pollutant subject to regulation'' as specified by CAA sections 165(a)(4) and 169(3). Major NSR permits for sources located in nonattainment areas and that emit at or above the specified major NSR threshold for the pollutant for which the area is designated as nonattainment are referred to as Nonattainment NSR (NNSR) permits. Sources subject to NNSR must, among other requirements, meet the Lowest Achievable Emission Rate (LAER) pursuant to CAA sections 171(3) and 173(a)(2) for any pollutant subject to NNSR. For the minor NSR program, neither the CAA nor the EPA's rules set forth a minimum control technology requirement.

In keeping with the goal of progress toward attaining the NAAQS, sources seeking NNSR permits must provide or purchase ''offsets''—*i.e.,* decreases in emissions that compensate for the increases from the new source or modification. For sources seeking PSD permits, offsets are not required, but they must demonstrate that the emissions from the project will not cause or contribute to a violation of the NAAQS or the ''PSD increments'' (*i.e.,* margins of ''significant'' air quality deterioration above a baseline concentration that establish an air quality ceiling, typically below the NAAQS, for each PSD area). Sources can often make this air quality demonstration based on the BACT level of control or by accepting more stringent air quality-based limitations. However, if these methods are insufficient to show that increased emissions from the source will not cause or contribute to a violation of air quality standards, applicants may undertake mitigation measures that are analogous to offsets in order to satisfy this PSD permitting criterion.

When the EPA is making NSR permitting decisions, it has legal authority to consider potential disproportionate environmental burdens on a case-by-case basis. Based on Executive Order (E.O.) 12898, the EPA's Environmental Appeals Board (EAB) has held that environmental justice considerations must be considered in connection with the issuance of Federal PSD permits issued by EPA Regional Offices or states acting under delegations of Federal authority. The EAB ''has . . . encouraged permit issuers to examine any 'superficially plausible' claim that a minority or low-income population may be disproportionately affected by a particular facility.'' [989] EPA guidance and EAB decisions do not advise EPA Regional Offices or delegated NSR permitting authorities to integrate environmental justice considerations into any particular component of the PSD permitting review, such as the determination of BACT. The practice of EPA Regional Offices and delegated states has been to conduct a largely freestanding environmental justice analysis for PSD permits that can take into account case-specific factors germane to any individual permit decision.

The minimum requirements for an approvable state NSR permitting program do not require state permitting authorities to reflect environmental justice considerations in their permitting decisions. However, states that implement NSR programs under an EPA-approved SIP have discretion to consider environmental justice in their NSR permitting actions and adopt additional requirements in the permitting decision to address potential disproportionate environmental burdens. Additionally, in some cases, a

[986] 40 CFR 52.21(b)(1)(i).

[987] 40 CFR 52.21(b)(2)(i) and the term ''net emissions increase'' as defined at 40 CFR 52.21(b)(3).

[988] For the PSD program, ''regulated NSR pollutant'' includes any pollutant for which a NAAQS has been promulgated (''criteria pollutants'') and any other air pollutant that meets the requirements of 40 CFR 52.21(b)(50). Some of these non-criteria pollutants include greenhouse gases, fluorides, sulfuric acid mist, hydrogen sulfide, and total reduced sulfur.

[989] *In re Shell Gulf of Mexico, Inc.,* 15 E.A.D. 103, 149 and n.71 (EAB 2010) (internal citations omitted).

state law requires consideration of environmental justice in the state's permitting decisions.

Through the NSR permit review process, permitting authorities have requirements for public participation in decision-making, which provide discretion for permitting authorities to provide enhanced engagement for communities with environmental justice concerns. This includes opportunities to enhance environmental justice by facilitating increased public participation in the formal permit consideration process (*e.g.,* by granting requests to extend public comment periods, holding multiple public meetings, or providing translation services at hearings in areas with limited English proficiency). The permitting authority can also take informal steps to enhance participation earlier in the process, such as inviting community groups to meet with the permitting authority and express their concerns before a draft permit is issued.

Additionally, in accordance with CAA 165(a)(2), the PSD regulations require the permitting authority to ''[p]rovide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations.'' 40 CFR 51.166(q)(2)(v). The ''alternatives'' and ''other appropriate considerations'' language in CAA 165(a)(2) can be interpreted to provide the permitting authority with discretion to incorporate siting and environmental justice considerations when issuing PSD permits—specifically, to impose permit conditions on the basis of environmental justice considerations raised in public comments regarding the air quality impacts of a proposed source. The EAB has recognized that consideration of the need for a facility is within the scope of CAA 165(a)(2) when a commenter raises the issue. The EPA has recognized that this language provides a potential statutory foundation in the CAA for this discretion.[990] The Federal regulations for NNSR permits also have an analysis of alternatives required by CAA 173(a)(5). 40 CFR 51.165(i).

1. Control Technology Reviews for Major NSR Permits

The statutory and regulatory basis for a control technology review for a source undergoing major NSR permitting differs from the criteria required in establishing an NSPS or emission guidelines. As such, sources that are permitted under major NSR may have differing control requirements for a pollutant than what is required by an applicable standard under CAA section 111. As noted above, sources permitted under the minor NSR program do not have a minimum control technology standard specified by statute or EPA rule, so a permitting authority has more flexibility in its determination of control technology for aminor NSR permit.

For PSD permits, the permitting authority must establish emission limitations based on BACT for each pollutant that is subject to PSD at the new major stationary source or at each emissions unit involved in the major modification. BACT is assessed on a case-by-case basis, and the permitting authority, in its analysis of BACT for each pollutant, evaluates the emission reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic, and other costs associated with each technology or technique. The CAA also specifies that BACT cannot be less stringent than any applicable standard of performance under the NSPS.[991]

In conducting a BACT analysis, many permitting authorities apply the EPA's five-step ''top-down'' approach, which the EPA recommends to ensure that all the criteria in the CAA's definition of BACT are considered. This approach begins with the permitting authority identifying all available control options that have the potential for practical application for the regulated NSR pollutant and emissions unit under evaluation. The analysis then evaluates each option and eliminates options that are technically infeasible, ranks the remaining options from most to least effective, evaluates the energy, environmental, economic impacts, and other costs of the options, eliminates options that are not achievable based on these considerations from the top of the list down, and ultimately selects the most effective remaining option as BACT.[992]

While the BACT review process is intended to capture a broad array of potential options for pollution control, the EPA has recognized that the list of available control options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. Thus, BACT should generally not be applied to regulate the permit applicant's purpose or objective for the proposed facility. However, this approach does not preclude a permitting authority from considering options that would change aspects (either minor or significant) of an applicants' proposed facility design in order to achieve pollutant reductions that may or may not be deemed achievable after further evaluation at later steps of the process. The EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire. The ''redefining the source'' issue is ultimately a question of degree that is within the discretion of the permitting authority, and any decision to exclude an option on ''redefining the source'' grounds should be explained and documented in the permit record.

In conducting the analysis of energy, environmental and economic impacts arising from each control option remaining under consideration, permitting authorities have considerable discretion in deciding the specific form of the BACT analysis and the weight to be given to the particular impacts under consideration. The EPA and other permitting authorities have most often used this analysis to eliminate more stringent control technologies with significant or unusual effects that are unacceptable in favor of the less stringent technologies with more acceptable collateral environmental effects. Permitting authorities may consider a wide variety of environmental impacts in this analysis, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, demand on local water resources, and emissions of other pollutants subject to NSR or pollutants not regulated under NSR such as air toxics. A permitting authority could place more weight on the collateral environmental effect of a control alternative on local communities—*e.g.,* if emission increases of co-pollutants from operating the control device may disproportionately

[990] See Memorandum from Gary S. Guzy, EPA General Counsel, titled *EPA Statutory and Regulatory Authorities Under Which Environmental Justice Issues May Be Addressed in Permitting* (December 1, 2000).

[991] 42 U.S.C. 7479(3) (''In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to [CAA Section 111 or 112].'').

[992] For more information on EPA's recommended BACT approach, see U.S. Environmental Protection Agency, New Source Review Workshop Manual (October 1990; Draft) at *https://www.epa.gov/sites/default/files/2015-07/documents/1990wman.pdf* and U.S. Environmental Protection Agency, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011; EPA–457/B–11–001) at *https://www.epa.gov/sites/default/files/2015-07/documents/ghgguid.pdf.*

affect a minority or low-income population—which may result in the permitting authority eliminating that control option and ultimately selecting a less stringent control technology for the target pollutant as BACT because it has more acceptable collateral impacts.

In addition, this analysis may extend to considering reduced, or excessive, energy or environmental impacts of the control alternative at an offsite location that is in support the operation of the facility obtaining the permit. For example, in the case of a facility that proposes to co-fire its new stationary combustion turbines with hydrogen procured from an offsite production facility, a permitting authority may determine it is appropriate to weigh favorably a control option that involves co-firing with hydrogen produced from low-GHG emitting processes, such as electrolysis powered by renewable energy, to recognize the reduced environmental impact of producing the fuel for the control option.

For NNSR permits, the statutory requirement for establishing LAER is more prescriptive and, consequently, tends to provide less discretion to permitting authorities than the discretion allowed under BACT. For new major stationary sources and major modifications in nonattainment areas, LAER is defined as the most stringent emission limitation required under a SIP or achieved in practice for a class or category of sources. Thus, unlike BACT, the LAER requirement does not consider economic, energy, or other environmental factors, except that LAER is not considered achievable if the cost of control is so great that a major new stationary source could not be built or operated.[993] As with BACT determinations, a determination of LAER cannot be less stringent than any applicable NSPS.[994]

2. NSR Implications of the NSPS

Any source that is planning to install a new or reconstructed EGU that meets the applicability of this final NSPS will likely require an NSR permit prior to its construction. In addition to including conditions for GHG emissions, the NSR permit would contain emission limitations for the non-GHG pollutants emitted by the new or reconstructed EGU. Depending on the level of emissions for each pollutant, the source may require a major NSR permit, minor NSR permit, or a combination of both types of permits.

As GHGs are regulated pollutants under the PSD program, this NSPS serves as the minimum level of control in determining BACT for any new major stationary source or major modification that meets the applicability of this NSPS and commences construction on its affected EGU(s) after the date of publication of the proposed NSPS in the **Federal Register**. However, as explained above, the fact that a minimum control requirement for BACT is established by an applicable NSPS does not mean that a permitting authority cannot select a more stringent control level for the PSD permit or consider control technologies for BACT beyond those that were considered in developing the NSPS. The authority for BACT is separate from that of BSER, and it requires a case-by-case review of a specific stationary source at the time its owner or operator applies for a PSD permit. Accordingly, the BACT analysis for a source with an applicable NSPS should reflect source-specific factors and any advances in control technology, reductions in the costs or other impacts of using particular control strategies, or other relevant information that may have become available after the EPA issued the NSPS.

3. NSR Implications of the Emission Guidelines

With respect to the final emission guidelines, each state will develop a plan that establishes standards of performance for each affected EGU in the state that meets the applicability criteria of this emission guidelines. In doing so, a state agency may develop a plan that requires an existing stationary source to undertake a physical or operational change. Under the NSR program, when a stationary source undertakes a physical or operational change, even if it is doing so to comply with a national or state level requirement, the source may need to obtain a preconstruction NSR permit, with the type of permit (*i.e.,* NNSR, PSD, or minor NSR) depending on the amount of the emissions increase resulting from the change and the air quality designation at the location of the source for its emitted pollutants. However, since emission guidelines are intended to reduce emissions at an existing stationary source, a NSR permit may not be needed to perform the physical or operational change required by the state plan if the change will not increase emissions at the source.

As noted elsewhere in this preamble, sources that will be complying with their state plan's standards of performance by installing and operating CCS could experience criteria pollutant emission increases that may result in the source triggering major NSR requirements. If a source with an affected EGU does trigger major NSR requirements for one or more pollutants as a result of complying with its standards of performance, the permitting authority would conduct a control technology review (*i.e.,* BACT or LAER, as appropriate) for each of the pollutants and require that the source comply with the other applicable major NSR requirements. As noted in section VII of this preamble, in light of concerns expressed by stakeholders over possible co-pollutant increases from CCS retrofit projects, the EPA plans to review its NSR guidance and determine how it can be updated to better assist permit applicants and permitting authorities in conducting BACT reviews for sources that intend to install CCS.

States may also establish the standards of performance in their plans in such a way so that their affected sources, in complying with those standards, in fact would not have emission increases that trigger major NSR requirements. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the standards of performance, their emissions would not increase in a way that trigger major NSR requirements. For example, a state could, as part of its state plan, develop enforceable conditions for a source expected to trigger major NSR that would effectively limit the unit's ability to increase its emissions in amounts that would trigger major NSR (effectively establishing a synthetic minor limitation).[995] Some commenters asserted that base load units may not be able to readily rely on this option to limit their emission increases given the need for those units to respond to demand and maintain grid reliability. In these cases, states may adopt other strategies in their state plans to ensure that base load units have the needed flexibility to operate and do so without triggering major NSR requirements.

[993] New Source Review Workshop Manual (October 1990; Draft), page G.4.

[994] 42 U.S.C. 7501(3); 40 CFR 51.165(a)(1)(xiii); 40 CFR part 51, appendix S, section II.A.18.

[995] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. See, *e.g.,* CAA sections 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or title V permitting programs. See, *e.g.,* 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of ''potential to emit'').

B. Title V Program

Title V regulations require each permit to include emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements. Requirements resulting from these rules that are imposed on EGUs or other potentially affected entities that have title V operating permits are applicable requirements under the title V regulations and would need to be incorporated into the source's title V permit in accordance with the schedule established in the title V regulations. For example, if the permit has a remaining life of 3 years or more, a permit reopening to incorporate the newly applicable requirement shall be completed no later than 18 months after promulgation of the applicable requirement. If the permit has a remaining life of less than 3 years, the newly applicable requirement must be incorporated at permit renewal.[996] Additionally, proceedings to reopen and issue a permit shall follow the same procedures that apply to initial permit issuance and only affect the parts of the permit for which cause to reopen exists. The reopening of permits is expected to be made as expeditiously as possible.[997]

In the proposal, the EPA also indicated that if a state needs to include provisions related to the state plan in a source's title V permit before submitting the plan to the EPA, these limits should be labeled as ''state-only'' or ''not federally enforceable'' until the EPA has approved the state plan. The EPA solicited comments on whether, and under what circumstances, states might use this mechanism. While no specific comments were received on this point, the EPA would like to further clarify that in finalizing this direction, the intention is to ensure that meaningful public participation is available during the development of a state plan, rather than limiting engagement to the permitting process. While the public would have the opportunity to comment on the individual permit provisions, this would not allow for the opportunity to comment on the plan as a whole before it is finalized.

XII. Summary of Cost, Environmental, and Economic Impacts

In accordance with E.O. 12866 and 13563, the guidelines of the Office of Management and Budget (OMB) Circular A–4 and the EPA's Guidelines for Preparing Economic Analyses, the EPA prepared an RIA for these final actions. The RIA is separate from the EPA's statutory BSER determinations and did not influence the EPA's choice of BSER for any of the regulated source categories or subcategories. This RIA presents the expected economic consequences of the EPA's final rules, including analysis of the benefits and costs associated with the projected emission reductions for three illustrative scenarios. The first scenario represents the final NSPS and emission guidelines in combination. The second and third scenarios represent different stringencies of the combined policies. All three illustrative scenarios are compared against a single baseline. For detailed descriptions of the three illustrative scenarios and the baseline, see section 1 of the RIA, which is titled ''Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from new, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule'' and is available in the rulemaking docket.[998]

The three scenarios detailed in the RIA, including the final rules scenario, are illustrative in nature and do not represent the plans that states may ultimately pursue. As there are considerable flexibilities afforded to states in developing their state plans, the EPA does not have sufficient information to assess specific compliance measures on a unit-by-unit basis. Nonetheless, the EPA believes that such illustrative analysis can provide important insights.

In the RIA, the EPA evaluates the potential impacts of the three illustrative scenarios using the present value (PV) of costs, benefits, and net benefits, calculated for the years 2024 to 2047 from the perspective of 2019. In addition, the EPA presents the assessment of costs, benefits, and net benefits for specific snapshot years, consistent with the Agency's historic practice. These specific snapshot years are 2028, 2030, 2035, 2040, and 2045. In addition to the core benefit-cost analysis, the RIA also includes analyses of anticipated economic and energy impacts, environmental justice impacts, and employment impacts.

The analysis presented in this preamble section summarizes key results of the illustrative final rules scenario. For detailed benefit-cost results for the three illustrative scenarios and results of the variety of impact analysis just mentioned, please see the RIA, which is available in the docket for this action.

It should be noted that for the RIA for this rulemaking, the EPA undertook the same approach to determine benefits and costs as it has generally taken in prior rulemakings concerning the electric power sector. It does not rely on the benefit-cost results included in the RIA as part of its BSER analysis. Rather, the BSER analysis considers the BSER criteria as set out in CAA section 111(a)(1) and the caselaw—including the costs of the controls to the source, the amount of emission reductions, and other criteria—as described in section V.C.2.

A. Air Quality Impacts

For the analysis of the final rules, total cumulative power sector CO_2 emissions between 2028 and 2047 are projected to be 1,382 million metric tons lower under the illustrative final rules scenario than under the baseline. Table 4 shows projected aggregate annual electricity sector emission changes for the illustrative final rules scenario, relative to the baseline.

TABLE 4—PROJECTED ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE

	CO_2 (million metric tons)	Annual NO_X (thousand short tons)	Ozone season NO_X (thousand short tons)	Annual SO_2 (thousand short tons)	Direct $PM_{2.5}$ (thousand short tons)	Mercury (tons)
2028	−38	−20	−6	−34	−2	−0.1

[996] *See* 40 CFR 70.7(f)(1)(i).

[997] *See* 40 CFR 70.7(f)(2).

[998] The EPA also examined the final rules under a variety of different assumptions regarding demand, gas price, and contemporaneous rulemakings and determined that those alternative projections, inclusive of CCS buildout and cost profiles, would not alter any BSER design parameters selected in this action. For further discussion, see the technical memorandum, *IPM Sensitivity Runs,* available in the rulemaking docket.

TABLE 4—PROJECTED ELECTRICITY SECTOR EMISSION IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE—Continued

	CO_2 (million metric tons)	Annual NO_X (thousand short tons)	Ozone season NO_X (thousand short tons)	Annual SO_2 (thousand short tons)	Direct $PM_{2.5}$ (thousand short tons)	Mercury (tons)
2030	−50	−20	−7	−20	−2	−0.1
2035	−123	−49	−19	−90	−1	−0.1
2040	−54	−6	−6	−4	2	0.2
2045	−42	−24	−14	−41	−2	−0.2

Note: Ozone season is the May through September period in this analysis.

B. Compliance Cost Impacts

The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and illustrative scenarios, including the cost of monitoring, reporting, and recordkeeping. In simple terms, these costs are an estimate of the increased power industry expenditures required to comply with the final actions.

The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the plans that states may ultimately pursue. The illustrative final rules scenario is designed to reflect, to the extent possible, the scope and nature of the final rules. However, there is uncertainty with regards to the precise measures that states will adopt to meet the requirements because there are flexibilities afforded to the states in developing their state plans.

The IRA is projected to accelerate the ongoing shift towards lower-emitting technology. In particular, under the baseline tax credits for low-emitting technology results in growing generation share for renewable resources and the deployment of 11 GW of CCS retrofits on existing coal-fired steam generating units by 2035. New combined cycle builds are 20 GW by 2030, and existing coal capacity continues to decline, falling to 84 GW by 2030 and 31 GW by 2040. Under the illustrative final rules scenario, the EPA projects an incremental 8 GW of CCS retrofits on existing coal-fired steam generating units by 2035 relative to the baseline. By 2035, relative to the baseline, new combined cycle builds are 2 GW lower, new combustion turbine builds are 10 GW higher, and wind and solar additions are 15 GW higher. Total coal capacity is projected to be 73 GW in 2030 and 19 GW by 2040. As a result, the compliance cost of the final rules is lower than it would be absent the IRA.

We estimate the PV of the projected compliance costs for the analysis of the final standards for new combustion turbines and for existing steam generating EGUs over the 2024 to 2047 period, as well as estimate the equivalent annual value (EAV) of the flow of the compliance costs over this period. The EAV represents a flow of constant annual values that, had they occurred annually, would yield a sum equivalent to the PV. All dollars are in 2019 dollars. We estimate the PV and EAV using discount rates of 2 percent, 3 percent, and 7 percent.[999] The PV of compliance costs discounted at the 2 percent rate is estimated to be about 19 billion, with an EAV of about 0.98 billion. At the 3 percent rate, the PV of compliance costs is estimated to be about 15 billion, with an EAV of about 0.91 billion. At the 7 percent discount rate, the PV of compliance costs is estimated to be about 7.5 billion, with an EAV of about 0.65 billion. To put this in perspective, this levelized compliance cost is roughly one percent of the total projected levelized cost to produce electricity over the same timeframe under the baseline.

Section 3 of the RIA presents detailed discussions of the compliance cost projections for the final rule requirements, as well as projections of compliance costs for less and more stringent regulatory options.

C. Economic and Energy Impacts

These final actions have economic and energy market implications. The energy impact estimates presented here reflect the EPA's illustrative analysis of the final rules. States are afforded flexibility to implement the final rules, and thus the estimated impacts could be different to the extent states make different choices than those assumed in the illustrative analysis. In addition, as discussed in section VII.E.1 of this preamble, the factors driving these impacts, including potential revenue streams for captured carbon, may change over the next 25 years, leading the estimated impacts to be different than reality. Table 5 presents a variety of energy market impact estimates for 2028, 2030, 2035, 2040, and 2045 for the illustrative final rules scenario, relative to the baseline.

TABLE 5—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE

[Percent change]

	2028 (%)	2030 (%)	2035 (%)	2040 (%)	2045 (%)
Retail electricity prices	−1	0	1	0	1
Average price of coal delivered to power sector	−1	−1	0	0	−32
Coal production for power sector use	−6	−4	−21	15	−84
Price of natural gas delivered to power sector	−2	0	3	0	0
Price of average Henry Hub (spot)	−2	−1	3	0	0

[999] Results using the 2 percent discount rate were not included in the proposals for these actions. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default rates to discount social costs and benefits. The analysis of the proposed rules used these two recommended rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent rate to discount social costs and benefits (subject to regular updates). The Circular A–4 update also recommended consideration of the shadow price of capital when costs or benefits are likely to accrue to capital. As a result of the update to Circular A–4, we include cost and benefits results calculated using a 2 percent discount rate.

TABLE 5—SUMMARY OF CERTAIN ENERGY MARKET IMPACTS FOR THE ILLUSTRATIVE FINAL RULES SCENARIO, RELATIVE TO THE BASELINE—Continued

[Percent change]

	2028 (%)	2030 (%)	2035 (%)	2040 (%)	2045 (%)
Natural gas use for electricity generation	−1	−2	4	0	2

These and other energy market impacts are discussed more extensively in section 3 of the RIA.

More broadly, changes in production in a directly regulated sector may have effects on other markets when output from that sector—for these rules, electricity—is used as an input in the production of other goods. It may also affect upstream industries that supply goods and services to the sector, along with labor and capital markets, as these suppliers alter production processes in response to changes in factor prices. In addition, households may change their demand for particular goods and services due to changes in the price of electricity and other final goods prices. Economy-wide models—and, more specifically, computable general equilibrium (CGE) models—are analytical tools that can be used to evaluate the broad impacts of a regulatory action. A CGE-based approach to cost estimation concurrently considers the effect of a regulation across all sectors in the economy.

In 2015, the EPA established a Science Advisory Board (SAB) panel to consider the technical merits and challenges of using economy-wide models to evaluate costs, benefits, and economic impacts in regulatory analysis. In its final report, the SAB recommended that the EPA begin to integrate CGE modeling into applicable regulatory analysis to offer a more comprehensive assessment of the effects of air regulations.[1000] In response to the SAB's recommendations, the EPA developed a new CGE model called SAGE designed for use in regulatory analysis. A second SAB panel performed a peer review of SAGE, and the review concluded in 2020.[1001]

The EPA used SAGE to evaluate potential economy-wide impacts of these final rules, and the results are contained in section 5.2 of the RIA. Note that SAGE does not currently estimate changes in emissions nor account for environmental benefits. The annualized social cost estimated in SAGE for the finalized rules is approximately $1.32 billion (2019 dollars) between 2024 and 2047 using a 4.5 percent discount rate that is consistent with the internal discount rate in the model. Under the assumption that compliance costs from IPM in 2056 continue until 2081, the equivalent annualized value for social costs in the SAGE model is $1.51 billion (2019 dollars) over the period from 2024 to 2081, again using a 4.5 percent discount rate that is consistent with the internal discount rate of the model. The social cost estimate reflects the combined effect of the final rules' requirements and interactions with IRA subsidies for specific technologies that are expected to see increased use in response to the final rules. We are not able to identify their relative roles currently.

At proposal, the EPA solicited comment on the SAGE analysis presented in the RIA appendix. The SAGE analysis of the final rules is responsive to those comments. The comments received were supportive of the use of SAGE for estimating economy-wide social costs and other economy-wide impacts alongside the IPM-based cost and benefit estimates. The comments also suggested a variety of sensitivity analyses and several longer-term research goals for improving the capabilities of SAGE, such as adding a representation of emissions changes. For more detailed comment summaries and responses, see the response to comments in the docket for these actions.

Environmental regulation may affect groups of workers differently, as changes in abatement and other compliance activities cause labor and other resources to shift. An employment impact analysis describes the characteristics of groups of workers potentially affected by a regulation, as well as labor market conditions in affected occupations, industries, and geographic areas. Employment impacts of these final actions are discussed more extensively in section 5 of the RIA.

D. Benefits

This section includes the estimated total benefits and the estimated net benefits of the final rules.

1. Total Benefits

Pursuant to E.O. 12866, the RIA for these actions analyzes the benefits associated with the projected emission changes under the final rules to inform the EPA and the public about these projected impacts. These final rules are projected to reduce national emissions of CO_2, SO_2, NO_X, and $PM_{2.5}$, which we estimate will provide climate benefits and public health benefits. The potential climate, health, welfare, and water quality impacts of these emission changes are discussed in detail in the RIA. In the RIA, the EPA presents the projected monetized climate benefits due to reductions in CO_2 emissions and the monetized health benefits attributable to changes in SO_2, NO_X, and $PM_{2.5}$ emissions, based on the emissions estimates in illustrative scenarios described previously. We monetize benefits of the final rules and evaluate other costs in part to enable a comparison of costs and benefits pursuant to E.O. 12866, but we recognize that there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified or monetized.

We emphasize that the monetized benefits analysis is entirely distinct from the statutory BSER determinations finalized herein and is presented solely for the purposes of complying with E.O. 12866. As discussed in more detail in the proposal and earlier in this action, the EPA weighed the relevant statutory factors to determine the appropriate standards and did not rely on the monetized benefits analysis for purposes of determining the standards. E.O. 12866 separately requires the EPA to perform a benefit-cost analysis, including monetizing costs and benefits where practicable, and the EPA has conducted such an analysis.

The EPA estimates the climate benefits of GHG emissions reductions expected from the final rules using estimates of the social cost of greenhouse gases (SC–GHG) that reflect recent advances in the scientific

[1000] U.S. EPA. 2017. SAB Advice on the Use of Economy-Wide Models in Evaluating the Social Costs, Benefits, and Economic Impacts of Air Regulations. EPA–SAB–17–012.

[1001] U.S. EPA. 2020. Technical Review of EPA's Computable General Equilibrium Model, SAGE. EPA–SAB–20–010.

literature on climate change and its economic impacts and that incorporate recommendations made by the National Academies of Science, Engineering, and Medicine.[1002] The EPA published and used these estimates in the RIA for the Final Oil and Gas Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* which was signed by the EPA Administrator on December 2, 2023.[1003] The EPA solicited public comment on the methodology and use of these estimates in the RIA for the Agency's December 2022 Oil and Gas Supplemental Proposal and has conducted an external peer review of these estimates, as described further below. Section 4 of the RIA lays out the details of the updated SC–GHG used within this final rule.

The SC–GHG is the monetary value of the net harm to society associated with a marginal increase in GHG emissions in a given year, or the benefit of avoiding that increase. In principle, SC–GHG includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–GHG, therefore, reflects the societal value of reducing emissions of the gas in question by 1 metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect GHG emissions. In practice, data and modeling limitations restrain the ability of SC–GHG estimates to include all physical, ecological, and economic impacts of climate change, implicitly assigning a value of zero to the omitted climate damages. The estimates are, therefore, a partial accounting of climate change impacts and likely underestimate the marginal benefits of abatement.

Since 2008, the EPA has used estimates of the social cost of various greenhouse gases (*i.e.,* SC–CO_2, SC–CH_4, and SC–N_2O), collectively referred to as the ''social cost of greenhouse gases'' (SC–GHG), in analyses of actions that affect GHG emissions. The values used by the EPA from 2009 to 2016, and since 2021—including in the proposal—have been consistent with those developed and recommended by the IWG on the SC–GHG; and the values used from 2017 to 2020 were consistent with those required by E.O. 13783, which disbanded the IWG. During 2015–2017, the National Academies conducted a comprehensive review of the SC–CO_2 and issued a final report in 2017 recommending specific criteria for future updates to the SC–CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process.[1004] The IWG was reconstituted in 2021 and E.O. 13990 directed it to develop a comprehensive update of its SC–GHG estimates, recommendations regarding areas of decision-making to which SC–GHG should be applied, and a standardized review and updating process to ensure that the recommended estimates continue to be based on the best available economics and science going forward.

The EPA is a member of the IWG and is participating in the IWG's work under E.O. 13990. As noted in previous EPA RIAs (including in the proposal RIA for this rulemaking), while that process continues, the EPA is continuously reviewing developments in the scientific literature on the SC–GHG, including more robust methodologies for estimating damages from emissions, and is looking for opportunities to further improve SC–GHG estimation.[1005] In the December 2022 Oil and Gas Supplemental Proposal RIA,[1006] the Agency included a sensitivity analysis of the climate benefits of that rule using a new set of SC–GHG estimates that incorporates recent research addressing recommendations of the National Academies [1007] in addition to using the interim SC–GHG estimates presented in the *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990* [1008] that the IWG recommended for use until updated estimates that address the National Academies' recommendations are available.

The EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, *External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,* which explains the methodology underlying the new set of estimates and was included as supplemental material to the RIA for the December 2022 Oil and Gas Supplemental Proposal.[1009] The response to comments document can be found in the docket for that action.

To ensure that the methodological updates adopted in the technical report are consistent with economic theory and reflect the latest science, the EPA also initiated an external peer review panel to conduct a high-quality review of the technical report, completed in May 2023. The peer reviewers commended the Agency on its development of the draft update, calling it a much-needed improvement in estimating the SC–GHG and a significant step toward addressing the National Academies' recommendations with defensible modeling choices based on current science. The peer reviewers provided numerous recommendations for refining the presentation and for future modeling improvements, especially with respect to climate change impacts and associated damages that are not currently included in the analysis. Additional discussion of omitted impacts and other updates were incorporated in the technical report to address peer reviewer recommendations. Complete information about the external peer review, including the peer reviewer selection process, the final report with individual recommendations from peer reviewers, and the EPA's response to each recommendation is available on

[1002] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. National Academies Press.

[1003] U.S. EPA. (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.'' Washington, DC: U.S. EPA.

[1004] Ibid.

[1005] The EPA strives to base its analyses on the best available science and economics, consistent with its responsibilities, for example, under the Information Quality Act.

[1006] U.S. EPA. (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.'' Washington, DC: U.S. EPA.

[1007] Ibid.

[1008] Interagency Working Group on Social Cost of Carbon (IWG). 2021 (February). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990. United States Government.

[1009] Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances,'' Docket ID No. EPA–HQ–OAR–2021–0317, November 2023.

the EPA's website.[1010] An overview of the methodological updates incorporated into the new SC–GHG estimates is provided in the RIA section 4.2. A more detailed explanation of each input and the modeling process is provided in the technical report, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.*[1011]

In addition to CO_2, these final rules are expected to reduce annual, national total emissions of NO_X and SO_2 and direct $PM_{2.5}$. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$, reducing these emissions would reduce human exposure to annual average ambient $PM_{2.5}$ and would reduce the incidence of $PM_{2.5}$-attributable health effects. These final rules are also expected to reduce national ozone season NO_X emissions. In the presence of sunlight, NO_X and VOCs can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions in most locations reduces human exposure to ozone and the incidence of ozone-related health effects, though the degree to which ozone is reduced will depend in part on local concentration levels of VOCs. The RIA estimates the health benefits of changes in $PM_{2.5}$ and ozone concentrations. The health effect endpoints, effect estimates, benefit unit-values, and how they were selected are described in the *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits* TSD.[1012] Our approach for updating the endpoints and to identify suitable epidemiologic studies, baseline incidence rates, population demographics, and valuation estimates is summarized in section 4 of the RIA.

The following PV and EAV estimates reflect projected benefits over the 2024 to 2047 period, discounted to 2024 in 2019 dollars, for the analysis of the final rules. We monetize benefits of the final rules and evaluate other costs in part to enable a comparison of costs and benefits pursuant to E.O. 12866, but we recognize that there are substantial uncertainties and limitations in monetizing benefits, including benefits that have not been quantified. The projected PV of monetized climate benefits is about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent.[1013] The projected PV of monetized health benefits is about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Combining the projected monetized climate and health benefits yields a total PV estimate of about $390 billion and EAV estimate of $21 billion.

At a 3 percent discount rate, these final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$. Thus, these final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at a 3 percent rate.

At a 7 percent discount rate, these final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this benefits analysis and are estimated to be about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$. Thus, these final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at a 7 percent rate.

The results presented in this section provide an incomplete overview of the effects of the final rules. The monetized climate benefits estimates do not include important benefits that we are unable to fully monetize due to data and modeling limitations. In addition, important health, welfare, and water quality benefits anticipated under these final rules are not quantified. We anticipate that taking non-monetized effects into account would show the total benefits of the final rules to be greater than this section reflects. Discussion of the non-monetized health, climate, welfare, and water quality benefits is found in section 4 of the RIA.

2. Net Benefits

The final rules are projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent. The final rules are also projected to reduce emissions of NO_X, SO_2 and direct $PM_{2.5}$ leading to national health benefits from $PM_{2.5}$ and ozone in most years, producing a projected PV of monetized health benefits of about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Thus, these final rules are expected to generate a PV of monetized benefits of $390 billion, with an EAV of $21 billion discounted at a 2 percent rate. The PV of the projected compliance costs are $19 billion, with an EAV of about $0.98 billion discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $370 billion and EAV of about $20 billion.

At a 3 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at 3 percent. The PV of the projected compliance costs are about $15 billion, with an EAV of $0.91 billion discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $360 billion and an EAV of about $19 billion.

At a 7 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at 7 percent. The PV of the projected compliance costs are about $7.5 billion,

[1010] *https://www.epa.gov/environmental-economics/scghg-tsd-peer-review.*

[1011] U.S. EPA (2023). Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review,* ''Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.'' Washington, DC: U.S. EPA.

[1012] U.S. EPA. (2023). *Estimating $PM_{2.5}$- and Ozone-Attributable Health Benefits.* Research Triangle Park, NC: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Health and Environmental Impact Division.

[1013] Monetized climate benefits are discounted using a 2 percent discount rate, consistent with the EPA's updated estimates of the SC–CO_2. The 2003 version of OMB's Circular A–4 had generally recommended 3 percent and 7 percent as default discount rates for costs and benefits, though as part of the Interagency Working Group on the Social Cost of Greenhouse Gases, OMB had also long recognized that climate effects should be discounted only at appropriate consumption-based discount rates. In November 2023, OMB finalized an update to Circular A–4, in which it recommended the general application of a 2 percent discount rate to costs and benefits (subject to regular updates), as well as the consideration of the shadow price of capital when costs or benefits are likely to accrue to capital (OMB 2023). Because the SC–CO_2 estimates reflect net climate change damages in terms of reduced consumption (or monetary consumption equivalents), the use of the social rate of return on capital (7 percent under OMB Circular A–4 (2003)) to discount damages estimated in terms of reduced consumption would inappropriately underestimate the impacts of climate change for the purposes of estimating the SC–CO_2. See section 4.2 of the RIA for more discussion.

with an EAV of $0.65 billion discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $320 billion and an EAV of about $19 billion.

See section 7 of the RIA for additional information on the estimated net benefits of these rules.

E. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

For this action, the analysis described in this section and in the RIA is presented for the purpose of providing the public with an analysis of potential EJ concerns associated with these rulemakings, consistent with E.O. 14096. This analysis did not inform the determinations made to support the final rules.

The EPA defines EJ as ''the just treatment and meaningful involvement of all people regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environment so that people: (i) Are fully protected from disproportionate and adverse human health and environmental effects (including risks) and hazards, including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers; and (ii) have equitable access to a healthy, sustainable, and resilient environment in which to live, play, work, learn, grow, worship, and engage in cultural and subsistence practices.'' [1014] In recognizing that particular communities of EJ concern often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

1. Analytical Considerations

For purposes of analyzing regulatory impacts, the EPA relies upon its June 2016 ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' [1015] which provides recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time, resource constraints, and analytical challenges will vary by media and circumstance. The Technical Guidance states that a regulatory action may involve potential EJ concerns if it could: (1) Create new disproportionate impacts on communities with EJ concerns; (2) exacerbate existing disproportionate impacts on communities with EJ concerns; or (3) present opportunities to address existing disproportionate impacts on communities with EJ concerns through this action under development.

The EPA's EJ technical guidance states that ''[t]he analysis of potential EJ concerns for regulatory actions should address three questions: (1) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline? (2) Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration? (3) For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?'' [1016]

To address these questions in the context of these final rules, the EPA developed a unique analytical approach that considers the purpose and specifics of these rulemakings, as well as the nature of known and potential disproportionate and adverse exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential EJ characteristics (*e.g.,* residence of historically redlined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated. Also due to data and resource limitations, we discuss climate EJ impacts of this action qualitatively (section 6.3 of the RIA).

For these rules, we employ two types of analysis to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analysis can inform whether there are potential EJ concerns for population groups of concern in the baseline (question 1).[1017] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns due to the implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3).

In section 6 of the RIA, we utilize the two types of analysis to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to populations of potential EJ concern (section 6.4); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, life expectancy, redlining, Tribal land, age, sex, educational attainment, and degree of linguistic isolation (section 6.5). It is important to note that due to the corresponding small magnitude of the ozone and $PM_{2.5}$ concentration changes relative to the baseline concentrations in each modeled future year, these rules are expected to have a small impact on the distribution of exposures across each demographic group. Each of these analyses should be considered independently of each other as each was performed to answer separate questions and is associated with unique limitations and uncertainties.

a. Proximity Analyses

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local environmental stressors, such as local NO_2 and SO_2 emitted from affected sources in these final rules, traffic, or noise. The Agency has conducted a demographic analysis of the populations living near facilities impacted by these rules including 114 facilities for which the EPA is unaware of existing retirement plans by 2032, 23 facilities (a subset of the 114 facilities) with known retirement plans between 2033–2040, and 94 facilities (also a subset of the 114 facilities) without known retirement plans before 2040. The baseline analysis indicates that on average the populations living within 5 km and 10 km of 114 facilities impacted by the final rules without announced retirement by 2032 have a higher percentage of the population that is American Indian, below the Federal poverty level, and below two times the Federal poverty level than the national average. In addition, the population living within 50 kilometers of the same 114 facilities has a higher percentage of the population that is Black. Relating these results to EJ question 1, we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by

[1014] *https://www.federalregister.gov/documents/2023/04/26/2023-08955/revitalizing-our-nations-commitment-to-environmental-justice-for-all.*

[1015] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[1016] See *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[1017] The baseline for proximity analyses is current population information, whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

the regulatory actions for certain population groups of concern in the baseline (question 1). However, as proximity to affected facilities does not capture variation in baseline exposures across communities, nor does it indicate that any exposures or impacts will occur, these results should not be interpreted as a direct measure of exposure impact. The full results of the demographic analysis can be found in RIA section 6.4. The methodology and the results of the demographic analysis for the final rules are presented in a technical report, *Analysis of Demographic Factors for Populations Living Near Coal-Fired Electric Generating Units (EGUs) for the Section 111 NSPS and Emissions Guidelines—Final,* available in the docket for these actions.

b. Exposure Analyses

While the exposure analyses can respond to all three EJ questions, correctly interpreting the results requires an understanding of several important caveats. First, recognizing the flexibility afforded to each state in implementing the final guidelines, the results below are based on analysis of several illustrative compliance scenarios which represent potential compliance outcomes in each state. This analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment. It is also important to note that the potential emissions changes discussed below are relative to a projected baseline, and any localized decreases or increases are subject to the uncertainty of the baseline projections discussed in section 3.7 of the RIA. This uncertainty becomes increasingly relevant in later years in which baseline modeling projects substantial reductions in emissions relative to today. Furthermore, several additional caveats should be noted that are specific to the exposure analysis. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the NAAQS whereas the $PM_{2.5}$ metric is more similar to the long-term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state and fuel level emission data paired with facility-level baseline emissions and provided at a resolution of 12 square kilometers. Additionally, here we focus on air quality changes due to these rulemakings and infer post-policy ozone and $PM_{2.5}$ exposure burden impacts. Note, we discuss climate EJ impacts of these actions qualitatively (section 6.3 of the RIA).

Exposure analysis results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

These rules are also expected to reduce emissions of direct $PM_{2.5}$, NO_X, and SO_2 nationally. Because NO_X and SO_2 are also precursors to secondary formation of ambient $PM_{2.5}$ and because NO_X is a precursor to ozone formation, reducing these emissions would impact human exposure. Quantitative ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions, so they are performed to evaluate potential disproportionate impacts of these rulemakings. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from the EPA's EJ technical guidance more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. As discussed in the RIA, our analysis indicates that baseline ozone and $PM_{2.5}$ concentration will decline substantially relative to today's levels for all demographic groups in all future modeled years, and these baseline levels of ozone and $PM_{2.5}$ can be considered to be relatively low. However, there are differences in exposure among demographic groups within these relatively low levels of baseline exposure. Baseline $PM_{2.5}$ and ozone exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic populations, Asian populations, and those without a high school diploma may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian populations, residents of Tribal Lands, populations with higher life expectancy or with life expectancy data unavailable, children, and unemployed populations may also experience disproportionately higher ozone concentrations than the reference group. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the reference group. Therefore, also in response to question 1, there likely are potential EJ concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory actions for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications.

Relative to the low baseline levels of exposure modeled in future years for $PM_{2.5}$ and ozone, exposure analyses show that the final rules will result in modest but widespread reductions in $PM_{2.5}$ and ozone concentrations in virtually all areas of the country, although some limited areas may experience small increases in ozone concentrations relative to forecasted conditions without the rule. The extent of areas experiencing ozone increases varies among snapshot years. Due to the small magnitude of the exposure changes across population demographics associated with these rulemakings relative to the magnitude of the baseline disparities, we infer that post-policy EJ ozone and $PM_{2.5}$ concentration burdens are likely to remain after implementation of the regulatory action (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated compared to the baseline. Due to the very small magnitude of differences across demographic population post-policy impacts, we do not find evidence that disparities among communities with EJ concerns will be exacerbated or mitigated by the regulatory alternatives under consideration regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures for most demographic groups in the future years evaluated. In 2035, under the illustrative compliance scenarios analyzed, it is possible that Asian populations, Hispanic populations, and those linguistically isolated, and those living on Tribal land may experience a slight exacerbation of ozone exposure disparities at the national level (question 3), compared to baseline ozone levels. Additionally at the national level, those living on Tribal land may experience a slight exacerbation of ozone exposure disparities in 2040 and a slight mitigation of ozone exposure disparities in 2028 and 2030. At the state level,

ozone exposure disparities may be either mitigated or exacerbated for certain demographic groups, also to a small degree. As discussed above, it is important to note that this analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

2. Outreach and Engagement

As part of the regulatory development process for these rulemakings, and consistent with directives set forth in multiple Executive Orders, the EPA conducted extensive outreach with interested parties including Tribal nations and communities with environmental justice concerns. This outreach allowed the EPA to gather information from a variety of viewpoints while also providing parties with an overview of the EPA's work to reduce GHG emissions from the power sector.

Prior to the May 2023 proposal, the EPA opened a public docket for pre-proposal input.[1018] The EPA continued to engage with interested parties by speaking on the EPA National Community Engagement call and the National Tribal Air Association Policy Update call in September 2022. Following publication of the proposal, the EPA hosted two informational webinars on June 6 and 7, 2023, specially targeted towards tribal environmental professionals, tribal nations, and communities with environmental justice concerns. The purpose of these webinars was to provide an overview of the proposal, information on how to effectively engage in the regulatory process and provide the EPA an opportunity to answer questions. The EPA held virtual public hearings on June 13, 14, and 15, 2023, that allowed the public an opportunity to present comments and information regarding the proposed rules.

The EPA recently finalized revisions to the subpart Ba implementing regulations requiring states to conduct meaningful engagement with pertinent stakeholders as part of the state plan development process. The EPA underscores the importance of this part of the state plan development process. For more detailed information on meaningful engagement, see section X.E.1.b.i of this preamble.

[1018] EPA–HQ–OAR–2022–0723.

F. Grid Reliability Considerations and Reliability-Related Mechanisms

1. Overview

The Federal Energy Regulatory Commission (FERC) is the federal agency with vested authority to ensure reliability of the bulk power system (16 U.S.C. 824o). FERC oversees and approves reliability standards that are developed by NERC and then become mandatory for all owners and operators of the bulk power system. Regional wholesale energy markets, like RTOs, ISOs, public service commissions, balancing authorities, and reliability coordinators all have reliability related responsibilities. The EPA's role under the CAA section 111 is to reduce emissions of dangerous air pollutants, including those emitted from the electric power sector. In doing so, it has a long, and exemplary history of ensuring its public-health-based emissions standards and guidelines that impact the power sector are sensitive to reliability-related issues and constructed in a manner that does not interfere with grid operators' responsibility to deliver reliable power. The EPA met with many entities with responsibility over the reliability of the bulk power system in crafting these final rules to make certain the rules will not impede their ability to ensure reliability of the bulk power system. This section outlines the array of modifications made in these final actions, outlined in section I.G of this preamble, that collectively help ensure that these final actions will not interfere with systems operators' ability to continue providing reliable power. Additional to this suite of adjustments, the EPA is introducing both a short-term reliability mechanism for emergency situations and a reliability assurance mechanism available for states to include in their state plans for additional flexibility. In response to the May 2023 proposed rule, the EPA received extensive comments regarding grid reliability and resource adequacy from balancing authorities, independent system operators and regional transmission organizations, state regulators, power companies, and other stakeholders. The EPA engaged with each of these group of commenters to garner a granular understanding of their reliability-related concerns. Additionally, the EPA met repeatedly with technical staff and Commissioners of FERC, DOE, NERC, and other reliability experts during the course of this rulemaking. At FERC's invitation, the EPA participated in FERC's Annual Reliability Technical Conference on November 9, 2023. Further, the EPA solicited additional comment on reliability-related mechanisms as part of the November 2023 supplemental proposed rule.

Comment: Several comments from grid operators raised the concern that the proposed rules have the potential to trigger material negative impacts to grid reliability. Concerns coalesced around the loss of firm dispatchable assets which they view as outpacing the development and interconnection of new assets that do not possess commensurate reliability attributes. Other commenters maintained that the proposals included adequate lead times for reliability planning, and that reliability attributes are currently sourced by a collection of assets, and as such a collection of future assets will be able to provide the requisite reliability attributes. Some commenters also asserted that the proposals would actually improve transparency around unit-specific decisions, which are often not communicated transparently with adequate notice, leading to a better reliability planning process.

Response: These final rules include a number of flexibilities and rule adjustments that will accommodate appropriate planning decisions by affected sources, system planners, and reliability authorities in a way that allows for the continued reliable operation of the electric grid. These final actions also include adjustments and improvements, with specific provisions related to compliance timing and system emergencies, that address reliability concerns. The rules do not interfere with ongoing efforts by key stakeholders to appropriately plan for an evolving electric system. The EPA agrees that transparency around unit-specific planning is of paramount importance to enabling systems operators advanced notice to plan for continued reliable bulk power operations.

The EPA initiated follow-up conversations with all balancing authorities and systems operators that submitted public comments to ensure a granular and thorough understanding of all reliability-related concerns raised in response to the proposed rules. In addition, the EPA solicited additional comment on reliability related mechanisms in the supplemental proposal issued in November 2023. The EPA examined the record carefully and responded with a suite of changes to the proposal that, though not always explicitly directed at addressing concerns raised with respect to reliability, nonetheless collectively help ensure EPA's rules will not interfere

with grid operators' responsibilities to provide reliable power.

As discussed earlier in this preamble, the EPA is finalizing several adjustments to provisions in the proposed rules that address reliability concerns and ensure that these rules provide adequate flexibilities and assurance mechanisms that allow grid operators to continue to fulfill their responsibilities to maintain the reliability of the bulk-power system. These adjustments include restructuring the subcategories for coal-fired steam generating EGUs: the EPA is not finalizing the proposed imminent or near term subcategory structure which should provide states with a wider planning latitude, and units with cease operations dates prior to January 1, 2032 are not regulated by this final rule. Importantly, the compliance timeline for installing CCS in the long-term subcategory has been extended by an additional 2 years. The EPA is not finalizing the 30 percent hydrogen co-firing BSER for the intermediate subcategory for new combustion turbines. These changes facilitate reliability planning and operations by providing more lead time for CCS installation-related compliance. The adjusted scope of these actions also provides additional time for the EPA to consult with a broad range of stakeholders, including grid operators, to deliberate and determine the best way to address emissions from existing gas turbines while respecting their contribution to electric reliability in the foreseeable future. In addition to these adjustments, as detailed in section X.D of this preamble, the EPA is offering states a suite of voluntary compliance flexibilities that could be used to address reliability concerns. These compliance flexibilities include clarifying the circumstances under which it may be appropriate for states to employ RULOF to establish source specific standards of performance and compliance schedules for affected EGUs to address reliability, allowing emission averaging, trading, and unit-specific mass-based compliance mechanisms for certain subcategories—provided that they achieve an equivalent level of emission reduction consistent with the application of individual rate-based standards of performance, and, for certain mechanisms, that they include a backstop emission rate, and offering a compliance date extension for affected new and existing EGUs that encounter unanticipated delays with control technology implementation.

The EPA believes the adjustments made to the final rules outlined above are sufficient to ensure the rules can be implemented without impairing the ability of grid operators to deliver reliable power. The EPA is nonetheless finalizing additional reliability-related instruments to provide further certainty that implementation of these final rules will not intrude on grid operators' ability to ensure reliability. The short-term reliability mechanism is available for both new and existing units and is designed to provide additional flexibility through an alternative compliance strategy during acute system emergencies that threaten reliability. The reliability assurance mechanism will be available for existing units that intend to cease operating, but, for unforeseen reasons, need to temporarily remain online to support reliability beyond the planned cease operation date. This reliability assurance mechanism, which requires a specific and adequate showing of reliability need that is satisfactory to the EPA, is intended for circumstances where there is insufficient time to complete a state plan revision, and it is limited to the amount of time substantiated, which may not exceed 1 year. The EPA intends to consult with FERC for advice on applications of reliability need that exceed 6 months. These instruments will be presumptively approvable, provided they meet the requirements defined in these emission guidelines, if states choose to incorporate them into their plans.

Comment: Commenters from industry and grid operators expressed support for the inclusion of a requirement that states include in their state plans a demonstration of consultation with all relevant reliability authorities to facilitate planning. Other commenters asserted that the proposals included sufficient coordination with reliability authorities, through the Initial Reporting Milestone Status Report requirements.

Response: The EPA agrees that planning for reliability is critically important. Indeed, all stakeholders generally agree that effective planning is essential to ensuring electric reliability is maintained.[1019] State planning, including coordination and transparency across jurisdictions, is particularly important given that state plans in one jurisdiction can impact the reliability and resource adequacy of other system operators. The EPA is finalizing, as part of the state plan development process, that states are required to conduct meaningful engagement with stakeholders. As part of this required meaningful engagement, states are strongly encouraged to consult with the relevant balancing authorities and reliability coordinators for their affected sources and to share available unit-specific requirements and compliance information in a timely fashion. Sharing regulatory requirements and unit-specific compliance information with balancing authorities and reliability coordinators in a timely manner will promote early and informed reliability planning. Strong system-planning processes of utility transmission companies and RTOs are among the most important tools to assure that reliability will not be adversely affected by regulations.[1020] [1021] A robust planning process that recognizes the different roles of states and their relevant balancing authorities, transmission planners, and reliability coordinators should help to identify potential resource adequacy or reliability issues early in the state planning process. States will also be able to address reliability-related issues through a revision in their state plan, including to address issues that were not foreseen during the state planning process.

In addition to these measures, DOE has authority pursuant to section 202(c) of the Federal Power Act to, on its own motion or by request, order, among other things, the temporary generation of electricity from particular sources in certain emergency conditions, including during events that would result in a shortage of electric energy, when the Secretary of Energy determines that doing so will meet the emergency and serve the public interest. An affected source operating pursuant to such an order is deemed not to be operating in violation of its environmental requirements. Such orders may be issued for 90 days and may be extended in 90-day increments after consultation with EPA. DOE has historically issued section 202(c) orders at the request of electric generators and grid operators such as RTOs in order to enable the supply of additional generation in times of expected emergency-related generation shortfalls.

Congress provided section 202(c) as the primary mechanism to ensure that when generation is needed to meet an emergency, environmental protections will not prevent a source from meeting that need. To date, section 202(c) has worked well, allowing, for example,

[1019] ''Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023,'' Susan Tierney, Analysis Group, November 7, 2023.

[1020] ''Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023,'' Susan Tierney, November 7, 2023.

[1021] ''Modernizing Governance: Key to Electric Grid Reliability'', Kleinman Center for Energy Policy, University of Pennsylvania, March 2024.

additional generation to come online to meet demand in the California Independent System Operator and PJM territories in 2022.[1022] Section 202(c) has also been used to allow generators to remain online pending completion of infrastructure needed to facilitate reliable replacement of those generators. The EPA continues to believe that section 202(c) is an effective mechanism for meeting the purpose of ensuring that all physically available generation will be available as needed to meet an emergency situation, regardless of environmental regulatory constraints. Given the heightened concerns about reliability expressed by commenters in the context of this rule and ongoing changes in the electricity sector, however, this final action includes an additional supplemental short-term reliability mechanism that states may elect to include in their state plans. States that adopt this mechanism could make it available for sources to use without needing action by DOE under section 202(c). Of course, section 202(c) would continue to be available for sources subject to this rule for emergency situations where EPA's short-term reliability mechanism would not apply.

Many electric reliability and bulk-power system authorities, including FERC and the regulated wholesale markets, are actively engaged in activities to ensure the reliability of the transmission grid, while paying careful attention to the changing resource mix and the ongoing trends in the power sector.[1023] [1024] There are multiple agencies and entities that have some authority and responsibility to ensure electric reliability. These include state utility commissions, balancing authorities, reliability coordinators, DOE, FERC, and NERC. The EPA's central mission is to protect human health and the environment and the EPA does not have direct authority or responsibility to ensure electric reliability. Still, the EPA believes reliability of the bulk power system is of paramount importance, and has included additional measures in these final actions that are delineated throughout this section, evaluated the resource adequacy implications in the final TSD, *Resource Adequacy Analysis,* and conducted capacity expansion modeling of the final rules in a manner that takes into account resource adequacy needs. Additionally, the EPA performed a variety of other sensitivity analyses including an examination of higher electricity demand (many areas are reporting accelerated load growth forecasts due to data centers, increased manufacturing, crypto currency, electrification and other factors) and the impact of the EPA's additional regulatory actions affecting the power sector. These sensitivity analyses indicate that, in the context of higher demand and other pending power sector rules, the industry has available pathways to comply with this rule that respect NERC reliability considerations and constraints. These results are detailed in the technical memoranda in the docket titled, *IPM Sensitivity Runs* and *Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG, and MATS.*

The EPA has carefully examined all comments related to reliability that were submitted during the public comment period for the proposal and for the supplemental notice. The Agency has engaged in dialogue with each of the balancing authorities regarding the content of their submitted comments. Based on this extensive engagement and consultation, the Agency's analysis of the impacts of these rules, and the various features of this rule that will work in tandem to ensure the standards and emission guidelines finalized here are achievable and can respond to future reliability and resource adequacy needs, the EPA has concluded these final rules will not interfere with grid operators' ability to continue delivering reliable power.

The EPA received a range of opinions during the comment process, and also during FERC's Annual Reliability Conference, some of which expressed that the proposed rule could provide a net benefit to reliability planning given the enhanced visibility into unit-specific compliance plans.[1025] This section discusses the additional compliance flexibilities and reliability instruments that have been included in these final rules.

The EPA has carefully considered the importance of reliability of the bulk-power system in developing these final rules. Stakeholders have recognized the EPA's long and successful history of ensuring its power sector rules are crafted to deliver significant public health benefits while not impairing the ability of grid operators to ensure reliable power.[1026] The entities responsible for ensuring reliability, which encompass electric utilities, RTOs and ISOs, reliability coordinators, other grid operators, utility and non-utility energy companies, and Federal and state regulators, have also historically met challenges in navigating power sector environmental obligations while maintaining reliability.[1027]

2. Compliance Flexibilities for New and Existing Affected EGUs

These final rules include three key compliance flexibilities for new and existing sources and reliability coordinators so that they can continue to plan for the reliable operation of the electric system; RULOF, emissions averaging and trading, and compliance extensions of up to 1 year for units installing control technology. As discussed in section X.C.2 of this preamble, states may use the RULOF provisions to address circumstances in which reliability or resource adequacy is a concern. Use of RULOF may be appropriate where reliability or resource adequacy considerations for a particular EGU are fundamentally different from those considered when developing these emission guidelines, which may make it unreasonable for an affected EGU to comply with a standard of performance by the prescribed date. Under these circumstances, the state may choose to particularize the compliance obligations for the affected EGU in order to address the reliability or resource adequacy concern. As explained in section X.C.2, the EPA believes any adjustments that are needed will take the form of different compliance timelines. RULOF is relevant at the stage of establishing standards of performance and compliance schedules to affected EGUs as a state plan is being developed or revised.

States have the ability to use emission averaging or trading, as well as unit-specific mass-based compliance, as described in section X.D of this preamble, which may also provide reliability-related benefits. The use of these alternative compliance flexibilities is not required, but states may employ these flexibilities, provided they demonstrate that their programs achieve an equivalent level of emission reduction with unit-specific application

[1022] DOE. DOE's Use of Federal Power Act Emergency Authority. *https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.*

[1023] See Resource Adequacy Analysis document for further analysis and exploration of these important elements.

[1025] ''In the current environment, grid operators are unsure about when resources may retire, increasing uncertainty and making planning harder. The proposed rules have long timelines for enactment, giving states, utilities, and grid operators plenty of time to plan for the transition.'' From ''Prepared Statement of Ric O'Connell Executive Director, GridLab,'' Testimony before FERC Annual Reliability Technical Conference on November 9, 2023.

[1026] ''Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants,'' Susan Tierney, November 7, 2023.

[1027] ''Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability,'' Susan Tierney, May 2014.

of rate-based standards of performance and apply requirements relevant to the particular flexibility, as specified in section X.D. These compliance flexibilities are voluntary, and states may choose whether to allow their use in state plans, subject to certain conditions. However, states may find that the reliability-specific adjustments discussed below provide sufficient flexibility in lieu of the mechanisms described in section X.D.

States may incorporate into their state plans a mechanism that allows compliance date extensions up to 1 year for an existing affected EGU that is in the process of installing a control technology to meet its standard of performance in the state plan, under specific circumstances, a detailed discussion can be found in section X.C.1.d of this document. As discussed in section VIII.N of this document, the Administrator may provide a similar extension for new combustion turbines. The state or Administrator may allow the extension of the compliance date if the source demonstrates a delay in the construction or implementation of the control technology resulting from causes that are entirely outside the owner or operator's control. These may include delays in obtaining a final construction permit, after a timely and complete application, or delays due to documented supply chain issues; for example, a backlog for step-up transformer equipment. This compliance date extension is not expressly offered for reliability purposes, but rather as a flexibility to account for unforeseen and uncontrollable lags in construction or implementation of control technology to meet the unit's standard of performance, in instances where a source can demonstrate efforts to comply by the required timeframes as part of these final actions, including evidence that it took the necessary steps to comply with sufficient lead time to meet the compliance schedule absent unusual problems, and that those problems are entirely outside the source's control and the source's actions or inactions did not contribute to the delay. This potential extension can help ensure that sufficient capacity is available by providing additional time for an affected EGU to operate for a specific amount of time while it resolves delays related to installation of pollution controls.

If the owner/operator of an affected EGU encounters a delay outside of the owner or operator's control, and which prevents the source from meeting its compliance obligations, the affected EGU must follow the procedures outlined in the state plan for documenting the basis for the extension.[1028] Any delay in implementation that will necessitate a compliance date extension of more than 1 year must be done through a state plan revision to adjust the compliance schedule using RULOF as a basis. See section X.C.2 of this preamble for information on RULOF.

A similar 1-year compliance date extension flexibility for units implementing control technologies that encounter a delay outside of the owner or operator's control which prevents the source from meeting compliance obligations is also available to certain new sources, which are directly regulated by the EPA. This is described in section VIII.N of this preamble.

3. Reliability Mechanisms

While the EPA believes the significant structural adjustments and compliance flexibilities that are discussed above are adequate to ensure that the implementation of these final rules does not interfere with systems operators' ability to ensure electric reliability, the EPA is also finalizing two reliability-related mechanisms as additional safeguards. These mechanisms include a short-term reliability mechanism for unexpected and short-duration emergency events, and a reliability assurance mechanism for units with retirement dates that are enforceable in the state plan, provided there is a documented and verified reliability concern. The EPA notes that these mechanisms must be included in the state plan to be utilized by the owners/operators of existing affected EGUs subject to requirements in the state plan. Sections XII.3.a, and XII.3.b of this preamble describe presumptively approvable methodologies for incorporating these mechanisms into a state plan.

a. Short-Term Reliability Mechanism

Comment: Multiple commenters requested an explicit short-term mechanism which could accommodate emergency situations and provide additional flexibility to affected sources. Commenters requested that the mechanism include additional rule flexibilities that could potentially be used during emergency conditions that would help reliability authorities avert a load shed event. A mechanism would function as an additional automated flexibility measure with a clearly articulated emergency provision for affected sources to respond to short-duration emergency grid situations. Some commenters requested a mechanism that is distinct from the process established by DOE's emergency authority under the Federal Power Act (section 202(c)), whereby DOE is required by the terms of section 202(c) to issue orders tailored to best meet particularized emergency circumstances.[1029] Other commenters highlighted the numerous rule flexibilities that were designed to accommodate reliability concerns and emergency conditions and indicated that the EPA's rule need not overly accommodate reliability and resource adequacy concerns since the primary burden for developing solutions falls to industry, grid operators, reliability coordinators, state planners, and other stakeholders. These commenters indicated that it is important to consider any trade-offs with additional flexibility measures, in particular any trade-offs with emissions implications.

Response: The EPA agrees with the latter commenters and expects that the broader adjustments in the final rules, in addition to the compliance flexibilities offered to states in section X.D of this document, along with DOE's pre-existing section 202(c) authority, are sufficient to enable an affected unit to respond to emergencies as needed and still comply with the annual requirements of these actions. As an additional safeguard measure, the EPA is finalizing a short-term reliability mechanism to assure that these final actions will not interfere with grid operators' ability to ensure electric reliability. More specifically, the EPA has determined that some accommodation during grid emergencies, which are rare, is warranted in order to provide some additional flexibility to help system planners, affected sources, state regulators, and reliability authorities meet demand and avert load shed when such emergencies occur. The EPA believes this additional flexibility is warranted, given the projected increase in extreme weather events exacerbated by climate change.

A short-term reliability mechanism for new sources is included in the final NSPS. Similarly, a short-term mechanism is offered to states to include in state plans for use with existing sources during specific and defined periods of time where the grid is under extreme strain. The short-term reliability mechanism is linked to specific conditions under which the system operators may not have

[1028] Assuming the affected EGU is in a state that has included the extension mechanism in its approved plan.

[1029] *https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.*

sufficient available generation to call upon to meet electric demand, and various reliability authorities have issued emergency alerts to rectify the situation. These emergency alerts are most often associated with extreme weather events where electric demand increases and there are often unexpected transmission and generation outages. Recent examples of short-term emergency alert conditions include Winter Storm Uri in 2021 and Winter Storm Elliot in 2022, both of which included unanticipated generator outages and triggered emergency grid operations. The EPA expects that the broader adjustments to the final rules, in combination with the compliance flexibilities described in section XII.F.2 of this document, are sufficient to enable an affected unit to respond to grid emergencies as needed and still comply with the annual requirements of these actions. Nonetheless, the EPA is finalizing this short-term reliability mechanism, available to states to include at their discretion, to provide an additional layer of assurance that these final actions will not interfere with the grid operator's ability to ensure electric reliability.

A short-term reliability mechanism is included for new sources in the final NSPS, and additionally offered to states to include in state plans for existing sources. The mechanism provides affected sources additional flexibility during rare and extreme emergency events, when all available generators are called upon to meet electric demand. For new sources, the mechanism allows sources to calculate applicability and compliance without using the emissions and operational data produced during these discrete events, with appropriate documentation.[1030] For existing sources, the mechanism allows sources to use the baseline emission rate during these discrete events, also with appropriate documentation.[1031]

The mechanism is only applicable during an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor, which requires plans and sets procedures for reliability entities to help avert disruptions in electric service during emergency conditions.[1032] The NERC reliability standard articulates roles and responsibilities, defines notification processes for reliability coordinators and operators, requires a plan for grid management practices, and specifies a compliance monitoring process. Notably, the standard defines three levels of Energy Emergency Alerts (EEA) that guide reliability coordinators during energy emergencies and assist with communicating information across the system and with the public to avert potential disruptions:

- *EEA–1:* All available generation resources in use—The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
- *EEA–2:* Load management procedures in effect—The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority. An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies. An energy deficient Balancing Authority is still able to maintain its minimum Contingency Reserve requirement.
- *EEA–3:* Firm Load interruption is imminent or in progress—The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

The alerts are typically issued in reaction to emergencies as they develop, are generally rare, and most often have been issued during extreme weather events, such as hurricanes, cold weather events, and heatwaves. The most concerning alert is EEA–3, where interruption of electric service through controlled load shed is imminent for some areas, although load shed does not necessarily occur under every EEA–3 declaration. According to NERC, 25 EEA–3s were declared in 2022, an increase of 15 EEA–3 declarations over 2021. Nine of the EEA–3 declarations in 2022 included shedding of firm load. While the number of declarations increased from 2021, the amount of load that was shed during the 2022 events was less than 10 percent of the previous year.[1033] All of the EEA–3 declarations in 2022 were related to extreme weather impacts, according to NERC.[1034]

Other emergency events (EEA–1 and EEA–2) are more frequent, although also relatively rare, based upon recent data. Data for the largest ISOs and RTOs indicate that EEA–1 and EEA–2 can occur several times over a year, for relatively brief periods in most instances, in response to developing reliability emergencies.[1035] Across the country, reliability coordinators (RCs) are charged by NERC to implement reliability standards and issue EEAs.[1036] The RCs monitor, track, and issue alerts according to the NERC alert protocol. This data is also generally supposed to be publicly available on each reliability coordinator's website, which documents the frequency and duration of emergency alerts. However, while there are requirements to report events where EEA–3 was declared to NERC[1037] and NERC publicly tracks use of EEA–3,[1038] EEA–1 events are the least likely to be documented consistently, for example, there is no similar publicly available tracking and reporting for use of EEA–1 alerts in a centralized and consistent manner.

Energy Emergency Alerts also have an important geographic and/or regional component, since most emergencies affect a particular geographic zone, and hence a smaller number of generators are subject to the alert in most instances.

[1030] The performance standard shall be the Phase I standard for the affected new source under the NSPS.

[1031] The baseline emission rate for existing sources is the CO_2 mass emissions and corresponding electricity generation data for a given affected EGU from any continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to the date the final rule is published in the **Federal Register**.

[1032] NERC Reliability Standards, *https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx*, and NERC Emergency Preparedness and Operations (Reliability Standard EOP–011–2). *https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-2.pdf*.

[1033] 2023 State of Reliability Technical Assessment, NERC. *https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf*.

[1034] Ibid.

[1035] Since 2021, ERCOT issued two EEA–1 events, two EEA–2 events, and one EEA–3 event (all for events occurring over an 8-hour period one day in 2021, and for 1 hour in 2023). In SPP, since 2021, there were eight EEA–1 events, five EEA–2 events, and two EEA–3 events (occurring over 5 days). The EEA–1 and EEA–2 events lasted between 1 and 19 hours. In MISO, there was a 2-day event in 2021 that resulted in an EEA magnitude 1, 2, or 3 alert through the day and into the next day. One EEA–1 event in 2022 lasted for a half hour and an EEA–2 event for 3 hours. In 2023, there was an EEA–2 event for 9.5 hours. In PJM, no alerts were issued in 2021. In 2022, roughly a dozen alerts were issued. Some lasted minutes, while others lasted half a day. One event stretched for 3 days. There were two alerts issued in 2023, lasting roughly 3 and 1 hours each. While this data is not comprehensive, it is indicative of the frequency and duration of emergency events that fall under the NERC reliability standard alert process. See: ERCOT Market Notices, SPP Historical Advisories and Alerts, *https://www.oasis.oati.com/SWPP/*; MISO Maximum Generation Emergency Declarations (2023), *https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf*; and MISO Maximum Generation Emergency Declarations (2023), *https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf*. See also PJM Emergency Procedures and Postings, *https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf*.

[1036] NERC Organization Certification (January 2024). *https://www.nerc.com/pa/comp/Pages/Registration.aspx*.

[1037] *https://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/M-11_Energy_Emergency_Alerts.pdf*.

[1038] *https://www.nerc.com/pa/RAPA/ri/Pages/EEA2andEEA3.aspx*.

During extreme and large-scale weather events, the alerts often cover a much broader geographic area, such as when Winter Storm Elliott impacted two-thirds of the lower 48 states and rapidly intensified into a bomb cyclone in December 2022. Many areas declared EEAs, and four states experienced operator-controlled load shed and 2.1 million customers experienced power outages.[1039] When these events occur, a much larger group of affected sources would be potentially covered.[1040] It should be noted that issuance of EEA's is not just dependent on a generator's availability, but also, generation deliverability, as transmission constraints due to operational conditions or planned maintenance activities can lead to issuance of EEA's that help ensure system stability and reliability.

The EPA's assessment is that these alerts generally occur infrequently, only rarely persist for as long as several days, and are indicative of a grid under strain. When the alerts are more prolonged, lasting for several days, they are generally dictated by persistent extreme weather with widespread impacts and a higher probability of load shed. The short-term reliability mechanism offers sources that come under a documented level 2 and or 3 EEA, combined with a documented request from the balancing authority to deviate from its scheduled operations, for example, by increasing output in response to the alert. In other words, only the specific units called upon, or otherwise instructed to increase output beyond the planned day-ahead or other near-term expected output during an EEA level 2 or 3 event are eligible for this flexibility, with proper documentation.

For new sources, the emissions and/or generation data will not be counted when determining applicability and the use of the sources' Phase 1 standard of performance may be used for compliance determinations through the duration of these events, as long as appropriate documentation is provided. For existing sources, states may choose to temporarily apply an alternative standard of performance, or a unit's baseline emission performance rate, when demonstrating compliance with the final standards, with appropriate documentation. It should be emphasized that these final emission guidelines require compliance with the standards of performance on an annual basis (or rolling annual average for new sources), as opposed to a shorter period such as hourly, daily, or monthly. This relatively long compliance period provides significant flexibility for sources that face circumstances whereby their emission performance may change temporarily due to various factors, including in response to grid emergency conditions. Nonetheless, this mechanism is included in these final rules to ensure that affected sources have the additional flexibility needed to meet demand during emergency conditions.[1041]

The short-term reliability mechanism references EEA–2 and EEA–3 for several reasons. First, balancing authorities and grid operators do not necessarily have to take action under EEA–1 conditions, such as calling on interruptible loads. As such, there is much less cost or inconvenience to declaring EEA–1, as a general matter, and EEA–2 and EEA–3 events are more aligned with events that are rare or truly represent emergency conditions. Second, EEA–1 events are a preparatory step in anticipation of potentially worsening conditions, as opposed to an indicator of imminent load-shed. Thus, under EEA–1, balancing authorities and grid operators do not generally take actions such as calling for voluntary demand reduction or calling on interruptible loads, and reliability coordinators are afforded more discretion for declaring an EEA–1. As such, there is much less cost or inconvenience to declaring EEA–1, as a general matter, and providing operational or cost relief under EEA–1 could create an incentive to deploy it more routinely. In addition, waiving significant regulatory requirements before taking actions such as calling for voluntary demand reductions or calling upon contractually arranged interruptible loads would not be commensurate to the significance of the various response actions. Third, reliability coordinators are afforded more discretion for declaring an EEA–1, and thus may have a potential incentive to deploy it more routinely if there is some operational or cost relief associated with it. And lastly, the reporting of EEA–1 is not consistent throughout the country, and there is some degree of opaqueness associated with the frequency and duration of EEA–1 events, thus making it a less robust mechanism threshold for purposes of aligning it with the requirements of this final action. For these reasons, the EPA believes that EEA–2 and EEA–3 are the appropriate threshold for inclusion in the short-term reliability mechanism and better represent rare or truly emergency conditions in which providing a limited exemption from a significant environmental requirement is justifiable.

Thus, the EPA believes that the selection of EEA–2 and EEA–3 are aligned with the conditions envisioned where an affected source might need temporarily relief, in order to offer reliability coordinators and balancing authorities the flexibility needed during emergency events to maintain reliability. In addition, as explained earlier, DOE's 202(c) authority is an additional mechanism that can be deployed under certain emergency conditions, which may occur outside any EEA–2 or EEA–3 event. These tools, either individually or in combination, help provide additional assurance that sources and reliability coordinators can continue to maintain a reliable system.

The mechanism is available to states to include in their state plans in an explicit manner, which will allow additional flexibility to sources in those states during short-term reliability emergencies. Inclusion of the reliability mechanism in a state plan must be part of the public comment process that each state must undertake. The comment process will afford full notice and the opportunity for the public comment, and the state plan will need to specify alternative performance standards for each specific affected source during these events (as defined in this section). The state plan must clearly indicate the specific parameters of emergency alerts cited as part of this mechanism, the relevant reliability coordinators that are authorized to issue the alerts in the state, and the compliance entities who are affected by this action (*i.e.,* affected sources). These sources must provide documentation of emergencies, as indicated in this section. The documentation must include evidence of the alert from the issuing entity, duration of the alert, and requests by reliability entities to sources to increase output in response to the emergency. The source must supply this

[1039] 2023 State of Reliability Technical Assessment, NERC. *https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf.*

[1040] For example, the entire footprint of SPP *currently* includes roughly 50 individual coal-steam units, reflecting roughly 19 GW of capacity.

[1040] For PJM, there are *currently* roughly 65 individual coal-steam units with total capacity of roughly 30 GW, which could potentially be covered by a regionwide alert. These estimates are considerably lower when known and committed coal-steam retirements are excluded. Within the PJM footprint, there are 27 control areas or transmission zones where emergency procedures are applied.

[1041] For example, units with installed CCS technology may be called upon to run at full capacity (*i.e.,* without the parasitic load of the carbon capture equipment). The EPA does not expect this to be a typical response as units are economically disincentivized to shut off or bypass control equipment given the tax credit incentives in IRC section 45Q.

information to the state regulatory entities and to the EPA when demonstrating compliance with the annual performance standards. This demonstration will indicate the discrete periods where the alternative standards or emission rates were in place, coinciding with the emergency alerts.

The calculation of the emission rate for an affected source in a state that adopts the short-term reliability mechanism must adhere to the following during potential emergency alerts:

- When demonstrating annual compliance with the standard of performance, the existing affected source may apply its baseline emission rate in lieu of its standard of performance for the hours of operation that correspond to the duration of the alert; and
- The existing affected EGU would demonstrate compliance based on application of its baseline emission performance rate standard of performance for the documented hours it operated under a revised schedule due to an EEA 2 or 3.
- For new sources, the EGU would demonstrate compliance based on application of its phase 1 performance standard for the documented hours it operated under a revised schedule due to an EEA 2 or 3. with the same documentation listed above.

Supplemental reporting, recordkeeping and documentation required:

- Documentation that the EEA was in effect from the entity issuing the alert, along with documentation of the exact duration of the event; [1042]
- Documentation from the entity issuing the alert that the EEA included the affected source/region where the unit was located; and
- Documentation that the source was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside of its scheduled dispatch during emergency conditions from a reliability coordinator, balancing authority, or ISO/RTO.

b. Reliability Assurance Mechanism

The EPA gave considerable attention and thought to comments from all stakeholders concerning potential reliability-related considerations. As noted earlier, the EPA engaged in extensive stakeholder outreach and provided additional opportunity for public comment as part of the supplemental notice for small businesses, since similar reliability-related concerns were raised. This section provides additional background, as well as approvable language, for a reliability assurance mechanism that states have the option to incorporate into their state plans.

Comment: Some commenters cautioned that EPA rules could exacerbate an ongoing concern that firm, dispatchable assets are exiting the grid at a faster pace than new capacity can be deployed and that most new electric generating capacity does not provide the equivalent reliability attributes as the capacity being retired. Several commenters provided examples where units with publicly announced retirement dates were delayed by reliability entities and coordinators due, in part, to the potential for energy shortfalls that might increase reliability risks in the ISO. Many commenters cited findings from NERC that highlighted the potential for capacity shortfalls, some of which are already in effect in some areas. Other commenters asserted that there is no need for a reliability assurance mechanism given the sufficient lead times in the proposal and the various flexibilities already provided. Some commenters included analysis that showed resource adequacy shortfalls over the forecasted time horizon were limited and manageable under the proposal.

Response: The EPA believes that the provisions in these final actions are sufficient to accommodate installation of pollution controls and reliability planning. The EPA has further articulated the use of RULOF, which can be deployed under the state planning and revision processes, for specific circumstances related to reliability. The EPA is also finalizing compliance flexibilities that can address delays to the installation or permitting of control technologies or associated infrastructure that are beyond the control of the EGU owner/operator. The EPA acknowledges that isolated issues could unfold over the course of the implementation timeline that could not have been foreseen during the planning process and that may require units to remain online beyond their planned cease operation dates to maintain reliability.

The EPA does not agree that the final rule will result in long-term adverse reliability impacts.[1043] [1044] Nevertheless, as an added safeguard, the EPA is finalizing a reliability assurance mechanism for existing affected sources that have committed to cease operation but, for unforeseen reasons, need to temporarily remain online to support reliability for a discrete amount of time beyond their planned date to cease operations. The primary mechanism to address reliability-related issues for units with cease operations dates is through the state plan revision process. This reliability assurance mechanism is designed to enable extensions for cease operation dates when there is insufficient time to complete a state plan revision. Under this reliability assurance mechanism, which can only be accessed if included in a state plan, units could obtain up to a 1-year extension of a cease operation date. If a state decides to include the mechanism in its state plan, then the mechanism must be disclosed during the public comment process that states must undertake. Under this reliability assurance mechanism, units may obtain extensions only for the amount of time substantiated through their applications and approved by the appropriate EPA Regional Administrator. For extension requests greater than 6 months, EPA will seek the advice of FERC in these cases and therefore applications must be submitted to FERC, as well as to the appropriate EPA Regional Administrator. The date from which an extension can be given is the enforceable date in the state plan, including any cease operation dates in state plans that are prior to January 1, 2032.

These provisions are similar in part to a reliability-related flexibility provided by the EPA for the MATS rule finalized in December 2011. On December 16, 2011, the EPA issued a memorandum [1045] outlining an Enforcement Response Policy whereby affected sources enter into a CAA section 113(a) administrative order for up to 1 year for narrow circumstances including when the deactivation of a unit or delay in installation of controls due to factors beyond the owner's/operator's control could have an adverse, localized impact on electric reliability. Under MATS, affected sources were required to come into compliance with standards within 3 years of the effective date. The EPA believed flexibility was warranted given potential constraints around the availability of control equipment and associated skilled workforce for all affected sources within the compliance window. While a 1-year extension as

[1042] *https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-2.pdf.*

[1043] ''Bulk System Reliability for Tomorrow's Grid'' The Brattle Group, December 20, 2023.

[1044] ''The Future of Resource Adequacy'' The Department of Energy, April 2024.

[1045] *https://www.epa.gov/sites/default/files/documents/mats-erp.pdf.*

part of CAA section 112(i)(3)(B) was broadly available to affected sources, additional time through an administrative order was limited to units that were demonstrated to be critical for reliability purposes under the Enforcement Response Policy.[1046] FERC's role in this process, which was developed with extensive stakeholder input,[1047] was to assess the submitted request to ensure any application was adequately substantiated with respect to its reliability-related claims. While several affected EGUs requested and were granted a 1-year CAA section 112(i)(3)(B) compliance extension by their permitting authority, OECA only issued five administrative orders in connection to the Enforcement Response Policy.[1048] These orders relied upon a FERC review of the reliability risks associated with the loss of specific units, following the accompanying FERC policy memorandum guidance.[1049] The 2012 MATS Final Rule was ultimately implemented over the 2015–2016 timeframe without challenges to grid reliability.

Given the array of adjustments made to the rule explained above, and the ability of states to address unanticipated changes in circumstances through the state plan revision process, the EPA does not anticipate that this mechanism, if included by states in the planning process, will be heavily utilized. This mechanism provides an assurance to system planners and affected sources, which can provide additional time for the state to execute a state plan revision, if needed. For states choosing to include this option in their state plans, the reliability assurance mechanism can provide units up to a 1-year extension of the scheduled cease operation date without a state plan revision, provided the reliability need is adequately justified and the extension is limited to the time for which the reliability need is demonstrated. This mechanism can accommodate situations when, with little notice, the relevant reliability authority determines that an EGU scheduled to cease operations is needed beyond that date, in order to maintain reliability during the 12 months leading up to or after the EGU is scheduled to retire. For potential situations in which system planners, affected sources, and reliability authorities identify a reliability concern, including a potential resource adequacy shortfall and an associated demonstration of increased loss of load expectation, more than one year in advance, this approach allows for the time needed for states to undertake a state plan revision process. The EPA recognizes that successful reliability planning involves many stakeholders and is a complex long-term process. For this reason, the EPA is encouraging states to consult electric reliability authorities during the state plan process, as part of the requirements under Meaningful Engagement (see section X.E.1.b.i of this document). The EPA acknowledges that there may be isolated instances in which the deactivation or retirement of a unit could have impacts on the electric grid in the future that cannot be predicted or planned for with specificity during the state planning process, wherein all anticipated reliability-related issues would be analyzed and addressed. This mechanism is not intended for use with units encountering unforeseen delays in installation of control technologies, as such issues are addressed through compliance flexibilities discussed in section XII.F.2, or for units subject to an obligation to operate that is not based on the reliability criteria included here.

To ensure that reliability claims, following the specific requirements delineated below, submitted through this mechanism are sufficiently well documented, the EPA is requiring that the unit's relevant reliability Planning Authority(ies) certify that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested. Additionally, the EPA intends to seek the advice of FERC, the Federal agency with authority to oversee the reliability of the bulk-power system, to incorporate a review of applications for this mechanism that request more than 6 months of additional operating time beyond the existing date by which the unit is scheduled to cease operations to resolve a reliability issue. Additional operating time is available for up to 12 months from the unit's cease operation date through this mechanism. Any relief request exceeding 12 months would need to be addressed through the state plan revision process outlined in section X.E.3. In determining whether to grant a request under this mechanism, the EPA will assess whether the associated Planning Authority's reliability analysis identifies and supports, in a detailed and reasoned fashion, anticipated noncompliance with a Reliability Standard, substantiated by specific metrics described below, should a unit go offline per its established commitment. To assist in its determination, the EPA will seek FERC's advice regarding whether analysis of the reliability risk and the potential for violation of a mandatory Reliability Standard or increased loss of load expectation is adequately supported in the filed documentation.

This mechanism is for existing sources that have relied on a commitment to cease operating for purposes of these emission guidelines. Such reliance might occur in three circumstances: (1) units that plan to cease operation before January 1, 2032, and that are therefore exempt because they have elected to have enforceable cease operations dates in the state plan; (2) affected EGUs that choose to employ 40 percent natural gas co-firing by 2030 with a retirement date of no later than January 1, 2039; or (3) affected EGUs that have source-specific standards of performance based on remaining useful life, pursuant to the RULOF provisions outlined in section X.C.2 of this document. In each of these cases, units would have a commitment to cease operating by a date certain. This mechanism would allow for extensions of those dates to address unforeseen reliability or reserve margin concerns that arise due to changes in circumstances after the state plan has been finalized. Therefore, the date from which an extension can be given under this mechanism is the enforceable cease operations date in the state plan, including those prior to January 1, 2032. Only operators/owners of units that have satisfied all applicable milestones, metrics, and reporting obligations outlined in section X.C.3, and section X.C.4 for units with cease operation dates prior to January 1, 2032, would be eligible to use this mechanism.

This mechanism creates additional flexibility for specified narrow circumstances for existing sources and provides additional time and flexibility to allow a state, if necessary, to submit a plan revision should circumstances persist. In other words, this mechanism would be for use only when there is insufficient time to complete a state plan revision.

States can decide whether to include this extension mechanism in their state plans. If included in a state plan, the mechanism would be triggered when a unit submits an application to the EPA Regional Administrator where it faces an unforeseen situation that creates a

[1046] December 16, 2011, memorandum, ''The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercery and Air Toxics Standard'' from Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance.

[1047] See FERC Docket No. PL12–1–000.

[1048] *https://www.epa.gov/enforcement/enforcement-response-policy-mercury-and-air-toxics-standard-mats.*

[1049] *https://www.ferc.gov/sites/default/files/2020-04/E-5_9.pdf.*

reliability issue should that unit go offline consistent with its commitment to cease operations—for example, if the reliability coordinator identifies an unexpected capacity shortfall and determines that a specific unit(s) in a state(s) is needed to remain operational to satisfy a specific and documented reliability concern related to a unit's planned retirement. This mechanism would allow extensions, if approved by the Regional EPA Administrator, for units to operate after committed retirement dates without a full state plan revision. Any existing standard of performance finalized in the state plan under RULOF or the natural gas co-firing subcategory would remain in place. States have the discretion to place additional requirements on units requesting extensions. The relevant EPA Regional Administrator would approve the reliability assurance application or reject it if it were found that that the reliability assertion was not adequately supported. Units would need to substantiate the claim that they must remain online for reliability purposes with documentation demonstrating a forecasted reliability failure should the unit be taken offline, and this justification would need to be submitted to the appropriate EPA Regional Administrator and, for extensions exceeding 6 months, also to FERC, as described below. Extensions would be granted only for the duration of time demonstrated through the documentation, not to exceed 12 months, inclusive of the 6-month extension that is available and the relevant Planning Authority(ies) must certify that the claims are accurate and that the identified reliability problem both exists and requires the specific relief requested. Any further extension would require a state plan revision.

The process and documentation required to demonstrate that a unit is required to stay online because it is reliability-critical is described in this section.

In order to use this mechanism for an extension, certain conditions must be met by the unit and substantiated in written electronic notification to the appropriate EPA Regional Administrator, with an identical copy submitted to FERC for extension requests exceeding 6 months. More specifically, those conditions are that, where appropriate, the EGU owner complied with all applicable reporting obligations and milestones as described in sections X.C.4 (for units in the medium-term subcategory and units relying on a cease operation date for a less stringent standard of performance pursuant to RULOF), and section X.E.1.b.ii (for units with cease operation dates before January 1, 2032). No less than 30 days prior to the compliance date for applications for extensions of less than 6 months, and no less than 45 days prior to the compliance date for applications for extensions exceeding 6 months, but no earlier than 12 months prior to the compliance date (any requests over 12 months prior to a compliance date should be addressed through state plan revisions), a written complete application to activate the reliability assurance mechanism must be submitted to the appropriate EPA Regional Administrator, with a copy submitted to the state, including information responding to each of the seven elements listed as follows.

A copy of an extension request exceeding 6 months must also be submitted to FERC through a process and at an office of FERC's designation, including any additional specific information identified by FERC and responding to each of the following elements:

(1) Analysis of the reliability risk if the unit were not in operation demonstrating that the continued operation of the unit after the applicable compliance date is critical to maintaining electric reliability, such that retirement of that unit would trigger one or more of the following: (A) would result in noncompliance with at least one of the mandatory reliability standards approved by FERC, or (B) would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, this requires a clear demonstration that each unit would be needed to maintain the targeted level of resource adequacy.[1050] In addition, a projection substantiating the duration of the requested extension must be included for the length of time that the unit is expected to extend its cease-operations date because it is reliability-critical with accompanying analysis supporting the timeframe, not to exceed 12 months. The demonstration must satisfactorily substantiate at least one of the two conditions outlined above. Any unit that has received a Reliability Must Run Designation or equivalent from a reliability coordinator or balancing authority would fit this description. The types of information that will be helpful, based on the prior reliability extension process developed for MATS between the EPA and FERC include, but are not limited to, system planning and operations studies, system restoration studies or plans, operating procedures, and mitigation plans required by applicable Reliability Standards as defined by FERC in its May 17, 2012, Policy Statement issued to clarify requirements for the reliability extensions available through MATS.[1051]

(2) Analysis submitted by the relevant Planning Authority that verifies the reliability related claims, or presents a separate and equivalent analysis, confirming the asserted reliability risk if the unit were not in operation, or an explanation of why such a concurrence or separate analysis cannot be provided, and where necessary, any related system wide or regional analysis. This analysis or concurrence must include a substantiation for the duration of the extension request.

(3) Copies of any written comments from third parties regarding the extension.

(4) Demonstration from the unit owner/operator, grid operator and other relevant entities that they have a plan that includes appropriate actions, including bringing on new capacity or transmission, to resolve the underlying reliability issue, including the steps and timeframes for implementing measures to rectify the underlying reliability issue.

(5) Retirement date extensions allowed through this mechanism will be granted for only the increment of time that is substantiated by the reliability need and supporting documentation and may not exceed 12 months, inclusive of the 6-month extensions available with RTO, ISO, and reliability coordinator certification.

(6) For units affected by these emissions guidelines, states may choose to require the application to identify the level of operation that is required to avoid the documented reliability risk, and consistent with that level propose alternative compliance requirements, such as alternative standards or consistent utilization constraints for the duration of the extension. The EPA Regional Office may, within 30 days of the submission, reject the application if the submission is incomplete with respect to the above requirements or if the reliability assertion is not adequately supported.

(7) Only owners/operators of units that have satisfied all applicable milestone and reporting requirements and obligations under section X.C.3., and section X.C.4 for units with cease

[1050] Probabilistic Assessment: Technical Guideline Document, NERC, August 2016.

[1051] ''Policy Statement on the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards'' FERC, Issued May 17, 2012, at PL12–1–000.

operation dates prior to January 1, 2032, may use this mechanism for an extension as those sources will have provided information enabling the state and the public to assess that the units have diligently taken all actions necessary to meet their enforceable cease operations dates and demonstrate the use of all available tools to meet reliability challenges. Units that have failed to meet these obligations may make extension requests through the state plan revision process.

The EPA intends to consult with FERC in a timely manner on reliability-critical claims given FERC's expertise on reliability issues. The EPA may also seek advice from other reliability experts, to inform the EPA's decision. The EPA intends to decide whether it will grant a compliance extension for a retiring unit based on a documented reliability need within 30 days of receiving the application for applications less than 6 months, and within 45 days for applications exceeding 6 months to account for time needed to consult with FERC. Whether to grant an extension to an owner/operator is solely the decision of the EPA Regional Administrator.

For units already subject to standards of performance through state plans including those co-firing until 2039, and for units with specific, tailored and differentiated compliance dates developed through RULOF that employ this mechanism, those standards would apply during the extension.

4. Considerations for Evaluating 111 Final Actions With Other EPA Rules

Consistent with the EPA's statutory obligations under a range of CAA programs, the Agency has recently initiated and/or finalized multiple rulemakings to reduce emissions of air pollutants, air toxics, and greenhouse gases from the power sector. The EPA has conducted an assessment of the potential impacts of these regulatory efforts on grid resource adequacy, which is examined and discussed in the final TSD, *Resource Adequacy Analysis.* This analysis is informed by regional reserve margin targets, regional transmission capability, and generator availability. Moreover, as described in this action, the EPA designs its programs, implementation compliance flexibilities, and backstop mechanisms to be robust to future uncertainties and various compliance pathways for the collective of market and regulatory drivers. Finally, the backstop reliability mechanisms discussed in this section are, by design, similar to mechanisms utilized in the EPA's proposed Effluent Limitations Guidelines (ELG) rulemaking. There, to ensure that units choosing to permanently cease the combustion of coal by a particular date in their permits are not restricted from operation in the event of an emergency related to load balancing, the permit conditions allow for grid emergency exemptions (88 FR 18900). Harmonizing the use of similar criteria for emergency related reliability concerns across the two rules further buttresses unit confidence that grid reliability and environmental responsibilities will not come into conflict. It also streamlines the demonstrations and evidence that a unit must provide in such events. This cross-regulatory harmonization ensures that the Agency can successfully meet its CWA and CAA responsibilities regarding public health in a manner consistent with grid stability as it has consistently done throughout its 54-year history.

The EPA has taken into consideration, to the extent possible, the alignment of compliance timeframes and other aspects of these policies for affected units. For each regulatory effort, there has been coordination and alignment of requirements and timelines, to the extent possible. The potential impact of these various regulatory efforts is further examined in the final TSD, *Resource Adequacy Analysis.* Additionally, the EPA considered the impact of this suite of power sector rules by performing a variety of sensitivity analyses described in XII.F.3. These considerations are discussed in the technical memoranda, *IPM Sensitivity* Runs and *Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG, and MATS,* available in the rulemaking docket.

XIII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, EPA, submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Any changes made in response to recommendations received as part of Executive Order 12866 review have been documented in the docket.

The EPA prepared an analysis of the potential costs and benefits associated with these actions. This analysis, ''Regulatory Impact Analysis for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule,'' is available in the docket and describes in detail the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates.

Table 6 presents the estimated present values (PV) and equivalent annualized values (EAV) of the projected climate benefits, health benefits, compliance costs, and net benefits of the final rules in 2019 dollars discounted to 2024. This analysis covers the impacts of the final standards for new combustion turbines and for existing steam generating EGUs. The estimated monetized net benefits are the projected monetized benefits minus the projected monetized costs of the final rules.

Under E.O. 12866, the EPA is directed to consider the costs and benefits of its actions. Accordingly, in addition to the projected climate benefits of the final rules from anticipated reductions in CO_2 emissions, the projected monetized health benefits include those related to public health associated with projected reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3 and 7 percent. As shown in section 4.3.9 of the RIA, there are health benefits in the years 2028, 2030, 2035, and 2045 and health disbenefits in 2040. The projected climate benefits in this table are based on estimates of the social cost of carbon ($SC–CO_2$) at a 2 percent near-term Ramsey discount rate and are discounted using a 2 percent discount rate to obtain the PV and EAV estimates in the table. The power industry's compliance costs are represented in this analysis as the change in electric power generation costs between the baseline and illustrative policy scenarios. In simple terms, these costs are an estimate of the increased power industry expenditures required to implement the final requirements.

These results present an incomplete overview of the potential effects of the final rules because important categories of benefits—including benefits from reducing HAP emissions—were not monetized and are therefore not reflected in the benefit-cost tables. The EPA anticipates that taking non-monetized effects into account would

show the final rules to have a greater net benefit than this table reflects.

TABLE 6—PROJECTED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULES, 2024 THROUGH 2047

[Billions 2019$, discounted to 2024] [a]

	Present value (PV)		
	2% Discount rate	3% Discount rate	7% Discount rate
Climate Benefits [c]	270	270	270
Health Benefits [d]	120	100	59
Compliance Costs	19	15	7.5
Net Benefits [e]	370	360	320
Equivalent Annualized Value (EAV) [b]			
Climate Benefits [c]	14	14	14
Health Benefits [d]	6.3	6.1	5.2
Compliance Costs	0.98	0.91	0.65
Net Benefits [e]	20	19	19
Non-Monetized Benefits [e]	Benefits from reductions in HAP emissions Ecosystem benefits associated with reductions in emissions of CO_2, NO_X, SO_2, PM, and HAP Reductions in exposure to ambient NO_2 and SO_2 Improved visibility (reduced haze) from $PM_{2.5}$ reductions		

[a] Values have been rounded to two significant figures. Rows may not appear to sum correctly due to rounding.

[b] The annualized present value of costs and benefits are calculated over the 24-year period from 2024 to 2047.

[c] Monetized climate benefits are based on reductions in CO_2 emissions and are calculated using three different estimates of the SC–CO_2 (under 1.5 percent, 2.0 percent, and 2.5 percent near-term Ramsey discount rates). For the presentational purposes of this table, we show the climate benefits associated with the SC–CO_2 at the 2 percent near-term Ramsey discount rate. Please see section 4 of the RIA for the full range of monetized climate benefit estimates.

[d] The projected monetized air quality related benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The projected health benefits are associated with several point estimates and are presented at real discount rates of 2, 3, and 7 percent. This table presents the net health benefit impact over the analytic timeframe of 2024 to 2047. As shown in section 4.3.9 of the RIA, there are health benefits in the years 2028, 2030, 2035, and 2045 and health disbenefits in 2040.

[e] Several categories of climate, human health, and welfare benefits from CO_2, NO_X, SO_2, PM and HAP emissions reductions remain unmonetized and are thus not directly reflected in the quantified benefit estimates in this table. See section 4.2 of the RIA for a discussion of climate effects that are not yet reflected in the SC–CO_2 and thus remain unmonetized and section 4.4 of the RIA for a discussion of other non-monetized benefits.

As shown in table 6, the final rules are projected to reduce greenhouse gas emissions in the form of CO_2, producing a projected PV of monetized climate benefits of about $270 billion, with an EAV of about $14 billion using the SC–$CO_2$ discounted at 2 percent. The final rules are also projected to reduce emissions of NO_X, SO_2 and direct $PM_{2.5}$ leading to national health benefits from $PM_{2.5}$ and ozone in most years, producing a projected PV of monetized health benefits of about $120 billion, with an EAV of about $6.3 billion discounted at 2 percent. Thus, these final rules are expected to generate a PV of monetized benefits of $390 billion, with an EAV of $21 billion discounted at a 2 percent rate. The PV of the projected compliance costs are $19 billion, with an EAV of about $0.98 billion discounted at 2 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $370 billion and EAV of about $20 billion.

At a 3 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $100 billion, with an EAV of about $6.1 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $370 billion, with an EAV of about $20 billion discounted at 3 percent. The PV of the projected compliance costs are about $15 billion, with an EAV of $0.91 billion discounted at 3 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $360 billion and an EAV of about $19 billion.

At a 7 percent discount rate, the final rules are expected to generate projected PV of monetized health benefits of about $59 billion, with an EAV of about $5.2 billion. Climate benefits remain discounted at 2 percent in this net benefits analysis. Thus, the final rules would generate a PV of monetized benefits of about $330 billion, with an EAV of about $19 billion discounted at 7 percent. The PV of the projected compliance costs are about $7.5 billion, with an EAV of $0.65 billion discounted at 7 percent. Combining the projected benefits with the projected compliance costs yields a net benefit PV estimate of about $320 billion and an EAV of about $19 billion.

We also note that the RIA follows the EPA's historic practice of using a detailed technology-rich partial equilibrium model of the electricity and related fuel sectors to estimate the incremental costs of producing electricity under the requirements of proposed and final major EPA power sector rules. In section 5.2 of the RIA for these actions, the EPA has also included an economy-wide analysis that considers additional facets of the economic response to the final rules, including the full resource requirements of the expected compliance pathways, some of which are paid for through subsidies. The social cost estimates in the economy-wide analysis and discussed in section 5.2 of the RIA are still far below the projected benefits of the final rules.

B. Paperwork Reduction Act (PRA)

1. 40 CFR Part 60, Subpart TTTT

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities

contained in the existing regulations and has assigned OMB control number 2060–0685.

2. 40 CFR Part 60, Subpart TTTTa

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2771.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

Respondents/affected entities: Owners and operators of fossil-fuel fired EGUs.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 2.

Frequency of response: Annual.

Total estimated burden: 110 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $12,000 (per year), includes $0 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

3. 40 CFR Part 60, Subpart UUUUa

This action does not impose an information collection burden under the PRA.

4. 40 CFR Part 60, Subpart UUUUb

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned EPA ICR number 2770.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This rule imposes specific requirements on state governments with existing fossil fuel-fired steam generating units. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit GHG emissions from these existing EGUs. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation) is estimated to be 89,000 hours at a total annual labor cost of $11.7 million. The annual burden for the Federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 24,000 hours at a total annual labor cost of $1.7 million. Burden is defined at 5 CFR 1320.3(b).

Respondents/affected entities: States with one or more designated facilities covered under subpart UUUUb.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 43.

Frequency of response: Once.

Total estimated burden: 89,000 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $11.7 million, includes $35,000 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

Pursuant to sections 603 and 609(b) of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. Summaries of the IRFA and Panel recommendations are presented in the supplemental proposed rule at 88 FR 80582 (November 20, 2023). The complete IRFA and Panel Report are available in the docket for this action.[1052]

As required by section 604 of the RFA, the EPA prepared a final regulatory flexibility analysis (FRFA) for this action. The FRFA provides a statement of the need for, and objectives of, the rule; addresses the issues raised by public comments on the IRFA for the proposed rule, including public comments filed by the Chief Counsel for Advocacy of the Small Business Administration; describes the small entities to which the rule will apply; describes the projected reporting, recordkeeping and other compliance requirements of the rule and their impacts; and describes the steps the agency has taken to minimize impacts on small entities consistent with the stated objectives of the Clean Air Act. The complete FRFA is available for review in the docket and is summarized here. The scope of the FRFA is limited to the NSPS. The impacts of the emission guidelines are not evaluated here because the emission guidelines do not place explicit requirements on the regulated industry. Those impacts will be evaluated pursuant to the development of a Federal plan.

In 2009, the EPA concluded that GHG emissions endanger our nation's public health and welfare. Since that time, the evidence of the harms posed by GHG emissions has only grown and Americans experience the destructive and worsening effects of climate change every day. Fossil fuel-fired EGUs are the nation's largest stationary source of GHG emissions, representing 25 percent of the United States' total GHG emissions in 2021. At the same time, a range of cost-effective technologies and approaches to reduce GHG emissions from these sources are available to the power sector, and multiple projects are in various stages of operation and development. Congress has also acted to provide funding and other incentives to encourage the deployment of these technologies to achieve reductions in GHG emissions from the power sector.

In this notice, the EPA is finalizing several actions under CAA section 111 to reduce the significant quantity of GHG emissions from fossil fuel-fired EGUs by establishing emission guidelines and NSPS that are based on available and cost-effective technologies that directly reduce GHG emissions from these sources. Consistent with the statutory command of CAA section 111, the final NSPS and emission guidelines reflect the application of the BSER that,

[1052] See Document ID No. EPA–HQ–OAR–2023–0072–8109 and Document ID No. EPA–HQ–OAR–2023–0072–8108.

taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated.

These final actions ensure that EGUs reduce their GHG emissions in a manner that is cost-effective and improve the emissions performance of the sources, consistent with the applicable CAA requirements and caselaw. These standards and emission guidelines will significantly decrease GHG emissions from fossil fuel-fired EGUs and the associated harms to human health and welfare. Further, the EPA has designed these standards and emission guidelines in a way that is compatible with the nation's overall need for a reliable supply of affordable electricity.

The significant issues raised in public comments specifically in response to the initial regulatory flexibility analysis came from the Office of Advocacy within the Small Business Administration (Advocacy). The EPA agreed that convening a SBAR Panel was warranted because the EPA solicited comment on a number of policy options that, if finalized, could affect the estimate of total compliance costs and therefore the impacts on small entities. The EPA issued an IRFA and solicited comment on regulatory flexibilities for small business in a supplemental proposed rule, published in November 2023.

Advocacy provided further substantive comments on the IRFA that accompanied the November 2023 supplemental proposed rule. The comments reiterated the concerns raised in its original comment letter on the proposed rule and further made the following claims: (1) the IRFA does not provide small entities an accurate description of the impacts of the proposed rule, (2) small entities remain concerned that the EPA has not taken reliability concerns seriously.

In response to these comments and feedback during the SBAR Panel, the EPA revised its small business assessment to incorporate the final SBA guidelines (effective March 17th 2023) when performing the screening analysis to identify small businesses that have built or have planned/committed builds of combustion turbines since 2017. The EPA also treated additional entities within this subset as small based on feedback received during the panel process. The net effect of these changes is to increase the total compliance cost attributed to small entities, and the number of small entities potentially affected. The EPA additionally increased the assumed delivered hydrogen price to $1.15/kg.

Further, the EPA is finalizing multiple adjustments to the proposed rule that ensure the requirements in the final actions can be implemented without compromising the ability of power companies, grid operators, and state and Federal energy regulators to maintain resource adequacy and grid reliability.

To estimate the number of small businesses potentially impacted by the NSPS, the EPA performed a small entity screening analysis for impacts on all affected EGUs by comparing compliance costs to historic revenues at the ultimate parent company level. The EPA reviewed historical data and planned builds since 2017 to determine the universe of NGCC and natural gas combustion turbine additions. Next, the EPA followed SBA size standards to determine which ultimate parent entities should be considered small entities in this analysis.

Once the costs of the rule were calculated, the costs attributed to small entities were calculated by multiplying the total costs to the share of the historical build attributed to small entities. These costs were then shared to individual entities using the ratio of their build to total small entity additions in the historical dataset.

The EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Of the 14 entities that own NGCC units considered in this analysis, three are projected to experience compliance costs greater than or equal to 1 percent of generation revenues in 2035 and none are projected to experience compliance costs greater than or equal to 3 percent of generation revenues in 2035.

Prior to the November 2023 supplemental proposed rule, the EPA convened a SBAR Panel to obtain recommendations from small entity representatives (SERs) on elements of the regulation. The Panel identified significant alternatives for consideration by the Administrator of the EPA, which were summarized in a final report. Based on the Panel recommendations, as well as comments received in response to both the May 2023 proposed rule and the November 2023 supplemental proposed rule, the EPA is finalizing several regulatory alternatives that could accomplish the stated objectives of the Clean Air Act while minimizing any significant economic impact of the final rule on small entities. Discussion of those alternatives is provided below.

Mechanisms for reliability relief: As described in section XII.F of this preamble, the EPA is finalizing several adjustments to provisions in the proposed rules that address reliability concerns and ensure that the final rules provide adequate flexibilities and assurance mechanisms that allow grid operators to continue to fulfill their responsibilities to maintain the reliability of the bulk-power system. The EPA is additionally finalizing additional reliability-related instruments to provide further certainty that implementation of these final rules will not intrude on grid operator's ability to ensure reliability. The short-term reliability emergency mechanism, which is available for both new and existing units, is designed to provide an alternative compliance strategy during acute system emergencies when reliability might be threatened. The reliability assurance mechanism will be available for existing units that intend to cease operating, but, for unforeseen reasons, need to temporarily remain online to support reliability beyond the planned cease operation date. This reliability assurance mechanism, which requires an adequate showing of reliability need, is intended to apply to circumstances where there is insufficient time to complete a state plan revision. Whether to grant an extension to an owner/operator is solely the decision of the EPA. Concurrence or approval of FERC is not a condition but may inform EPA's decision. These instruments will be presumptively approvable, provided they meet the requirements defined in these emission guidelines, if states choose to incorporate them into their plans.

Throughout the SBAR Panel outreach, SERs expressed concerns that the proposed rule will have significant reliability impacts, including that areas with transmission system limitations and energy market constraints risk power interruption if replacement generation cannot be put in place before retirements. SERs recommended that Regional Transmission Organizations (RTOs) be involved to evaluate safety and reliability concerns.

SERs additionally stated that the proposed rule relies on the continued development of technologies not currently in wide use and large-scale investments in new infrastructure and that the proposed rule pushes these technologies significantly faster than the infrastructure will be ready and sooner than the SERs can justify investment to their stakeholders and ratepayers. SERs stated that this is of particular concern for small entities that are retiring generation in response to other regulatory mandates and need to replace that generation to continue serving their customers.

The suite of comprehensive adjustments in the final rules, along with the two explicit reliability mechanisms are directly responsive to SER's statements and concerns about grid reliability and the impact of retiring generating on small businesses.

Subcategories: Throughout the SBAR Panel, SERs expressed concerns that control requirements on rural electric cooperatives may be an additional hardship on economically disadvantaged communities and small entities. SERs stated that the EPA should further evaluate increased energy costs, transmission upgrade costs, and infrastructure encroachment which are concrete effects on the disproportionately impacted communities. Additionally, SERs stated hydrogen and CCS cannot be BSER because they are not commercially available and viable in very rural areas.

The EPA solicited comment on potential exclusions or subcategories for small entities that would be based on the class, type, or size of the source and be consistent with the Clean Air Act. The EPA also solicited comment on whether rural electric cooperatives and small utility distribution systems (serving 50,000 customers or less) can expect to have access to hydrogen and CCS infrastructure, and if a subcategory for these units is appropriate.

The EPA evaluated public comments received and determined that establishing a separate subcategory for rural electric cooperatives was not warranted. However, the EPA is not finalizing the low-GHG hydrogen BSER pathway. In response to concerns raised by small business and other commenters, the EPA conducted additional analysis of the BSER criteria and its proposed determination that low-GHG hydrogen co-firing qualified as the BSER. This additional analysis led the EPA to assess that the cost of low-GHG hydrogen in 2030 will likely be higher than proposed, and these higher cost estimates and associated uncertainties related to its nationwide availability were key factors in the EPA's decision to revise its 2030 cost estimate for delivered low-GHG hydrogen and are reflected in the increased price. For CCS, as discussed in sections VIII.F.4.c.iv and VII.C.1.a of this preamble, the EPA considered geographic availability of sequestration, as well as the timelines, materials, and workforce necessary for installing CCS, and determined they are sufficient. Moreover, while the BSER is premised on source-to-sink CO_2 pipelines and sequestration, the EPA notes that many EGUs in rural areas are primed to take advantage of synergy with the broader deployment of CCS in other industries. Capture, pipelines, and sequestration are already in place or in advanced stages of deployment for ethanol production from corn, an industry rooted in rural areas. The high purity CO_2 from ethanol production provides advantageous economics for CCS.

The EPA believes the decision to not finalize a low-GHG hydrogen BSER pathway is responsive to SER's statements and concerns regarding the availability of low-GHG hydrogen in very rural areas.

In addition, the EPA is preparing a Small Entity Compliance Guide to help small entities comply with this rule. The guide will be available 60 days after publication of the final rule at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

D. Unfunded Mandates Reform Act of 1995 (UMRA)

The NSPS contain a Federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for the private sector in any one year. The NSPS do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538 for state, local, and tribal governments, in the aggregate. Accordingly, the EPA prepared, under section 202 of UMRA, a written statement of the benefit-cost analysis, which is in section XIII.A of this preamble and in the RIA.

The repeal of the ACE Rule and emission guidelines do not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and do not significantly or uniquely affect small governments. The emission guidelines do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop plans to implement the guidelines under CAA section 111(d) for designated EGUs. The burden for states to develop CAA section 111(d) plans in the 24-month period following promulgation of the emission guidelines was estimated and is listed in section XIII.B, but this burden is estimated to be below $100 million in any one year. As explained in section X.E.6, the emission guidelines do not impose specific requirements on tribal governments that have designated EGUs located in their area of Indian country.

These actions are not subject to the requirements of section 203 of UMRA because they contain no regulatory requirements that might significantly or uniquely affect small governments. In light of the interest in these actions among governmental entities, the EPA initiated consultation with governmental entities. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the ''Big 10'' organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, including the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and National Association of Regulatory Utility Commissioners to participate in the meeting. The purpose of the consultation was to provide general background on these rulemakings, answer questions, and solicit input from state and local governments. For a summary of the UMRA consultation see the memorandum in the docket titled *Federalism Pre-Proposal Consultation Summary.*[1053]

E. Executive Order 13132: Federalism

These actions do not have federalism implications as that term is defined in E.O. 13132. Consistent with the cooperative federalism approach directed by the Clean Air Act, states will establish standards of performance for existing sources under the emission guidelines set out in this final rule. These actions will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

Although the direct compliance costs may not be substantial, the EPA nonetheless elected to consult with representatives of state and local governments in the process of

[1053] See Document ID No. EPA–HQ–OAR–2023–0072–0033.

developing these actions to permit them to have meaningful and timely input into their development. The EPA's consultation regarded planned actions for the NSPS and emission guidelines. The EPA invited the following 10 national organizations representing state and local elected officials to a virtual meeting on September 22, 2022: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the ''Big 10'' organizations appropriate to contact for purpose of consultation with elected officials. Also, the EPA invited air and utility professional groups who may have state and local government members, including the Association of Air Pollution Control Agencies, National Association of Clean Air Agencies, and American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, and National Association of Regulatory Utility Commissioners to participate in the meeting. The purpose of the consultation was to provide general background on these rulemakings, answer questions, and solicit input from state and local governments. For a summary of the Federalism consultation see the memorandum in the docket titled *Federalism Pre-Proposal Consultation Summary.*[1054]

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

These actions do not have tribal implications, as specified in Executive Order 13175. The NSPS imposes requirements on owners and operators of new or reconstructed stationary combustion turbines and the emission guidelines do not impose direct requirements on tribal governments. Tribes are not required to develop plans to implement the emission guidelines developed under CAA section 111(d) for designated EGUs. The EPA is aware of two fossil fuel-fired steam generating units located in Indian country, and one fossil fuel-fired steam generating units owned or operated by tribal entities. The EPA notes that the emission guidelines do not directly impose specific requirements on EGU sources, including those located in Indian country, but before developing any standards for sources on tribal land, the EPA would consult with leaders from affected tribes. Thus, Executive Order 13175 does not apply to these actions.

Because the EPA is aware of tribal interest in these rules and consistent with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA offered government-to-government consultation with tribes and conducted outreach and engagement.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks Populations and Low-Income Populations

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is a significant regulatory action as defined by E.O. 12866(3)(f)(1), and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the Agency has evaluated the environmental health and welfare effects of climate change on children. GHGs contribute to climate change and are emitted in significant quantities by the power sector. The EPA believes that the GHG emission reductions resulting from implementation of these standards and guidelines will further improve children's health. The assessment literature cited in the EPA's 2009 Endangerment Findings concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects (74 FR 66524, December 15, 2009). The assessment literature since 2016 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience. These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More detailed information on the impacts of climate change to human health and welfare is provided in section III of this preamble. Under these final actions, the EPA expects that CO_2 emissions reductions will improve air quality and mitigate climate impacts which will benefit the health and welfare of children.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

These actions, which are significant regulatory actions under Executive Order 12866, are likely to have to have a significant adverse effect on the supply, distribution or use of energy. The EPA has prepared a Statement of Energy Effects for these actions as follows. The EPA estimates a 1.4 percent increase in retail electricity prices on average, across the contiguous U.S. in 2035, and a 42 percent reduction in coal-fired electricity generation in 2035 as a result of these actions. The EPA projects that utility power sector delivered natural gas prices will increase 3 percent in 2035. As outlined in the Final TSD, *Resource Adequacy Analysis,* available in the docket for this rulemaking, the EPA demonstrates that compliance with the final rules can be achieved while maintaining resource adequacy, and that the rules include additional flexibility measures designed to address reliability-related concerns. For more information on the estimated energy effects, please refer section 3 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This rulemaking involves technical standards. Therefore, the EPA conducted searches for the New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Method 19 of 40 CFR part 60, appendix A. No applicable voluntary consensus standards (VCS) were identified for EPA Method 19. For additional information, please see the March 23, 2023, memorandum titled *Voluntary Consensus Standard Results for New Source Performance Standards for*

[1054] See Document ID No. EPA–HQ–OAR–2023–0072–0033.

Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule.[1055]

In accordance with the requirements of 1 CFR part 51, the EPA is incorporating the following 10 voluntary consensus standards by reference in the final rule.

- ANSI C12.20–2010, American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010) is cited in the final rule to assure consistent monitoring of electric output. This standard establishes the physical aspects and acceptable performance criteria for 0.2 and 0.5 accuracy class electricity meters. These meters would be used to measure hourly electric output that would be used, in part, to calculate compliance with an emissions standard.
- ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014), is cited in the final rule to provide directions and rules for conduct and reporting of results of thermal performance tests for open cycle simple cycle combustion turbines. The object is to determine the thermal performance of the combustion turbine when operating at test conditions and correcting these test results to specified reference conditions. PTC 22 provides explicit procedures for the determination of the following performance results: corrected power, corrected heat rate (efficiency), corrected exhaust flow, corrected exhaust energy, and corrected exhaust temperature. Tests may be designed to satisfy different goals, including absolute performance and comparative performance.
- ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15, 1997), is cited in the final rule to provide uniform test methods and procedures for the determination of the thermal performance and electrical output of heat-cycle electric power plants and combined heat and power units (PTC 46 is not applicable to simple cycle combustion turbines). Test results provide a measure of the performance of a power plant or thermal island at a specified cycle configuration, operating disposition and/or fixed power level, and at a unique set of base reference conditions. PTC 46 provides explicit procedures for the determination of the following performance results: corrected net power, corrected heat rate, and corrected heat input.
- ASTM D388–99 (Reapproved 2004), Standard Classification of Coals by Rank, covers the classification of coals by rank, that is, according to their degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite. It is used to define coal as a fuel type which is then referenced when defining coal-fired electric generating units, one of the subjects of this rule.
- ASTM D396–98, Standard Specification for Fuel Oils, covers grades of fuel oil intended for use in various types of fuel-oil-burning equipment under various climatic and operating conditions. These include Grades 1 and 2 (for use in domestic and small industrial burners), Grade 4 (heavy distillate fuels or distillate/residual fuel blends used in commercial/industrial burners equipped for this viscosity range), and Grades 5 and 6 (residual fuels of increasing viscosity and boiling range, used in industrial burners).
- ASTM D975–08a, Standard Specification for Diesel Fuel Oils, covers seven grades of diesel fuel oils based on grade, sulfur content, and volatility. These grades range from Grade No. 1–D S15 (a special-purpose, light middle distillate fuel for use in diesel engine applications requiring a fuel with 15 ppm sulfur (maximum) and higher volatility than that provided by Grade No. 2–D S15 fuel) to Grade No. 4–D (a heavy distillate fuel, or a blend of distillate and residual oil, for use in low- and medium-speed diesel engines in applications involving predominantly constant speed and load).
- ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008) covers two grades of kerosene suitable for use in critical kerosene burner applications: No. 1–K (a special low sulfur grade kerosene suitable for use in non-flue-connected kerosene burner appliances and for use in wick-fed illuminating lamps) and No. 2–K (a regular grade kerosene suitable for use in flue-connected burner appliances and for use in wick-fed illuminating lamps). It is used to define kerosene, which is a type of uniform fuel listed in this rule.
- ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011) covers biodiesel (B100) Grades S15 and S500 for use as a blend component with middle distillate fuels. It is used to define biodiesel, which is a type of uniform fuel listed in this rule.
- ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010) covers fuel blend grades of 6 to 20 volume percent biodiesel with the remainder being a light middle or middle distillate diesel fuel, collectively designated as B6 to B20. It is used to define biodiesel blends, which is a type of uniform fuel listed in this rule.
- ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009) is cited in the final rule for its guidance on determining performance characteristics of stationary combustion turbines. ISO 2314 specifies guidelines and procedures for preparing, conducting and reporting thermal acceptance tests in order to determine and/or verify electrical power output, mechanical power, thermal efficiency (heat rate), turbine exhaust gas energy and/or other performance characteristics of open-cycle simple cycle combustion turbines using combustion systems supplied with gaseous and/or liquid fuels as well as closed-cycle and semi closed-cycle simple cycle combustion turbines. It can also be applied to simple cycle combustion turbines in combined cycle power plants or in connection with other heat recovery systems. ISO 2314 includes procedures for the determination of the following performance parameters, corrected to the reference operating parameters: electrical or mechanical power output (gas power, if only gas is supplied), thermal efficiency or heat rate; and combustion turbine engine exhaust energy (optionally exhaust temperature and flow).

The EPA determined that the ANSI, ASME, ASTM, and ISO standards, notwithstanding the age of the standards, are reasonably available because they are available for purchase from the following addresses: American National Standards Institute (ANSI), 25 West 43rd Street, 4th Floor, New York, NY 10036–7422, +1.212.642.4900, *info@ansi.org*, *www.ansi.org*; American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990, +1.800.843.2763, *customercare@asme.org*, *www.asme.org*; ASTM International, 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, +1.610.832.9500, *www.astm.org*; International Organization for Standardization (ISO), Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland, +41.22.749.01.11, *customerservice@iso.org*, *www.iso.org*.

[1055] See Document ID No. EPA–HQ–OAR–2023–0072–0032.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions that exist prior to these actions result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with environmental justice concerns. Baseline $PM_{2.5}$ and ozone and exposure analyses show that certain populations, such as residents of redlined census tracts, those linguistically isolated, Hispanic, Asian, and those without a high school diploma may experience higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indian populations, residents of Tribal Lands, populations with life expectancy data unavailable, children, and unemployed populations may also experience disproportionately higher ozone concentrations than the national average. Black populations may also experience disproportionately higher $PM_{2.5}$ concentrations than the national average.

For existing sources, the EPA believes that this action is not likely to change existing disproportionate and adverse disparities among communities with EJ concerns regarding $PM_{2.5}$ exposures in all future years evaluated and ozone exposures for most demographic groups in the future years evaluated. However, in 2035, under the illustrative compliance scenarios analyzed, it is possible that Asian populations, Hispanic populations, and those linguistically isolated, and those living on Tribal land may experience a slight exacerbation of ozone exposure disparities at the national level (EJ question 3). Additionally at the national level, those living on Tribal land may experience a slight exacerbation of ozone exposure disparities in 2040 and a slight mitigation of ozone exposure disparities in 2028 and 2030. At the state level, ozone exposure disparities may be either mitigated or exacerbated for certain demographic groups analyzed, also to a small degree. As discussed above, it is important to note that this analysis does not consider any potential impact of the meaningful engagement provisions or all of the other protections that are in place that can reduce the risks of localized emissions increases in a manner that is protective of public health, safety, and the environment.

For new sources, the EPA believes that it is not practicable to assess whether this action is likely to result in new disproportionate and adverse effects on communities with environmental justice concerns, because the location and number of new sources is unknown. However, the EPA believes that the projected total cumulative power sector reduction of 1,365 million metric tons of CO_2 emissions between 2028 and 2047 will have a beneficial effect on populations at risk of climate change effects/impacts. Research indicates that racial, ethnic, and low socioeconomic status, vulnerable lifestages, and geographic locations may leave individuals uniquely vulnerable to climate change health impacts in the U.S.

The information supporting this Executive Order review is contained in section XII.E of this preamble and in section 6, Environmental Justice Impacts of the RIA, which is in the public docket.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit the rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

XIV. Statutory Authority

The statutory authority for the actions in this rulemaking is provided by sections 111, 302, and 307(d)(1) of the CAA as amended (42 U.S.C. 7411, 7602, 7607(d)(1)). These actions are subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedures, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

For the reasons set forth in the preamble, the EPA amends 40 CFR part 60 as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Section 60.17 is amended by:

■ a. Revising paragraphs (d)(1), (g)(15) and (16), (h)(38), (43), (47), (145), (206), and (212), the introductory text of paragraph (i);

■ b. Removing note 1 to paragraph (k) and paragraph (l);

■ c. Redesignating paragraphs (j) through (u) as shown in the following table:

Old paragraph	New paragraph
(j)	(k).
(k)	(m).
(m) through (o)	(n) through (p).
(p) through (r)	(r) through (t).
(s)	(q).
(t)	(j).
(u)	(l).

■ d. Revising newly-redesignated paragraphs (j) and (l), the introductory text to newly-redesignated paragraph (m), newly-redesignated paragraph (n), and the introductory text to newly-redesignated paragraphs (o), (q), and (r).

The revisions read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(d) * * *

(1) ANSI No. C12.20–2010 American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes (Approved August 31, 2010); IBR approved for §§ 60.5535(d); 60.5535a(d); 60.5860b(a).

* * * * *

(g) * * *

(15) ASME PTC 22–2014, Gas Turbines: Performance Test Codes, (Issued December 31, 2014); IBR approved for §§ 60.5580; 60.5580a.

(16) ASME PTC 46–1996, Performance Test Code on Overall Plant Performance, (Issued October 15,1997); IBR approved for §§ 60.5580; 60.5580a.

* * * * *

(h) * * *

(38) ASTM D388–99 (Reapproved 2004) ε^1(ASTM D388–99R04), Standard Classification of Coals by Rank, (Approved June 1, 2004); IBR approved for §§ 60.41; 60.45(f); 60.41Da; 60.41b; 60.41c; 60.251; 60.5580; 60.5580a.

* * * * *

(43) ASTM D396–98, Standard Specification for Fuel Oils, (Approved April 10, 1998); IBR approved for §§ 60.41b; 60.41c; 60.111(b); 60.111a(b); 60.5580; 60.5580a.

* * * * *

(47) ASTM D975–08a, Standard Specification for Diesel Fuel Oils, (Approved October 1, 2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.

* * * * *

(145) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1,

2008); IBR approved for §§ 60.41b; 60.41c; 60.5580; 60.5580a.

* * * * *

(206) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b, 60.41c, 60.5580, and 60.5580a.

* * * * *

(212) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b, 60.41c, 60.5580, and 60.5580a.

* * * * *

(i) Association of Official Analytical Chemists, 1111 North 19th Street, Suite 210, Arlington, VA 22209; phone: (301) 927–7077; website: *https://www.aoac.org/*.

* * * * *

(j) CSA Group (CSA) (formerly Canadian Standards Association), 178 Rexdale Boulevard, Toronto, Ontario, Canada; phone: (800) 463–6727; website: *https://shop.csa.ca*.

(1) CSA B415.1–10, Performance Testing of Solid-fuel-burning Heating Appliances, (March 2010), IBR approved for §§ 60.534; 60.5476.

(2) [Reserved]

* * * * *

(l) European Standards (EN), European Committee for Standardization, Management Centre, Avenue Marnix 17, B–1000 Brussels, Belgium; phone: + 32 2 550 08 11; website: *https://www.en-standard.eu*.

(1) DIN EN 303–5:2012E (EN 303–5), Heating boilers—Part 5: Heating boilers for solid fuels, manually and automatically stoked, nominal heat output of up to 500 kW—Terminology, requirements, testing and marking, (October 2012), IBR approved for § 60.5476.

(2) [Reserved]

* * * * *

(m) GPA Midstream Association, 6060 American Plaza, Suite 700, Tulsa, OK 74135; phone: (918) 493–3872; website: *www.gpamidstream.org*.

* * * * *

(n) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland; phone: + 41 22 749 01 11; website: *www.iso.org*.

(1) ISO 8178–4: 1996(E), Reciprocating Internal Combustion Engines—Exhaust Emission Measurement—part 4: Test Cycles for Different Engine Applications, IBR approved for § 60.4241(b).

(2) ISO 2314:2009(E), Gas turbines–Acceptance tests, Third edition (December 15, 2009), IBR approved for §§ 60.5580; 60.5580a.

(3) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition, IBR approved for § 60.107a(d).

(4) ISO 10715:1997(E), Natural gas—Sampling guidelines, (First Edition, June 1, 1997), IBR approved for § 60.4415(a).

(o) National Technical Information Services (NTIS), 5285 Port Royal Road, Springfield, Virginia 22161.

* * * * *

(q) Pacific Lumber Inspection Bureau (formerly West Coast Lumber Inspection Bureau), 1010 South 336th Street #210, Federal Way, WA 98003; phone: (253) 835.3344; website: *www.plib.org*.

* * * * *

(r) Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Suite 115, Peachtree Corners, GA 30092; phone (800) 332–8686; website: *www.tappi.org*.

* * * * *

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

■ 3. Section 60.5508 is revised to read as follows:

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit or an integrated gasification combined cycle (IGCC) facility that commences construction after January 8, 2014, commences reconstruction after June 18, 2014, or commences modification after January 8, 2014, but on or before May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction after January 8, 2014, but on or before May 23, 2023, or commences reconstruction after June 18, 2014, but on or before May 23, 2023. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

■ 4. Section 60.5509 is revised to read as follows:

§ 60.5509 What are my general requirements for complying with this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commenced construction after January 8, 2014, but on or before May 23, 2023, or commenced reconstruction after June 18, 2014, but on or before May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (10) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating

of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this paragraph (b)(7) continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (*e.g.,* not connected to a natural gas pipeline).

(9) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

(10) Your EGU is subject to subpart TTTTa of this part.

■ 5. Section 60.5520 is revised to read as follows:

§ 60.5520 What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 or 2 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternate to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 2 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 2 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

■ 6. Section 60.5525 is revised to read as follows:

§ 60.5525 What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 or 2 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas ($HTIP_{ng}$) and the total heat input from all other fuels combined ($HTIP_o$) using one of the methods under § 60.5535(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard\ = \frac{\left(50 \times HTIP_{ng}\right) + \left(69 \times HTIP_O\right)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 or 2 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2) on or after October 23, 2015, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555(c)(3)(ii)(A), for units that are not in the Acid Rain Program.

(2) For an affected EGU that has commenced commercial operation (as defined in 40 CFR 72.2) prior to October 23, 2015:

(i) If the date on which emissions reporting is required to begin under 40 CFR 75.64(a) has passed prior to October 23, 2015, emissions reporting shall begin according to § 60.5555(c)(3)(i) (for Acid Rain program units), or according to § 60.5555(c)(3)(ii)(B) (for units that are not subject to the Acid Rain Program). The first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which the rule becomes effective; or

(ii) If the date on which emissions reporting is required to begin under 40 CFR 75.64(a) occurs on or after October 23, 2015, then the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 60.5555(c)(3)(ii)(A).

(3) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580) after the calendar month in which emissions reporting is required to begin under § 60.5555(c)(3)(iii).

(4) Electric sales by your affected facility generated when it operated during a system emergency as defined in § 60.5580 are excluded for applicability with the base load standard if you can sufficiently provide the documentation listed in § 60.5560(i).

■ 7. Section 60.5535 is amended by revising paragraphs (a), (b), (c)(3), (d)(1), (e), and (f) to read as follows:

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ''valid operating hours'', as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from equation F–11 in appendix F to 40

CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) * * *

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

* * * * *

(d) * * *

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb of CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

* * * * *

(e) Consistent with § 60.5520, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross energy output. The Administrator may approve such alternate methods for apportioning the gross energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 or 2 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected EGU sharing the stack is in compliance.

(2) As an alternative, or if the EGUs are subject to different emission standards in table 1 or 2 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

* * * * *

■ 8. Section 60.5540 is revised to read as follows:

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 or 2 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535(b) or (c), as applicable, and either the generating load data from § 60.5535(d)(1) for output-based calculations or the heat input data from § 60.5535(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (*Note:* For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of 40 CFR 75 are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the

parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535 for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output (consistent with § 60.5520) value reported under 40 CFR part 75 to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}] \quad \text{(Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \quad \text{(Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual 12-operating month emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual 12-operating month emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520 if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section.

Round off the result to two significant figures.

(b) In accordance with § 60.5520, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 or 2 to this subpart, or the emissions standard calculated in accordance with § 60.5525(a)(2).

■ 9. Section 60.5555 is amended by revising paragraphs (a)(2)(iv) and (v), (f), and (g) to read as follows.

§ 60.5555 What reports must I submit and when?

(a) * * *

(2) * * *

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

* * * * *

(f) If your affected EGU captures CO_2 to meet the applicable emissions standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to an EGU or facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

■ 10. Section 60.5560 is amended by adding paragraphs (h) and (i) to read as follows:

§ 60.5560 What records must I maintain?

* * * * *

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert, and documentation of the exact duration of the event;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located, and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

■ 11. Section 60.5580 is amended by:

■ a. Revising the definitions for ''Annual capacity factor'', and ''Base load rating'';

■ b. Revising and republishing the definition for ''Coal''; and

■ c. Revising the definitions for ''Combined cycle unit'', ''Combined head and power unit or CHP unit'', ''Design efficiency'', ''Distillate oil'', ''ISO conditions'', ''Net electric sales'', and ''System emergency''.

The revisions and republications read as follows:

§ 60.5580 What definitions apply to this subpart?

* * * * *

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM International in ASTM D388–99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one

of the following methods: ASME PTC 22–2014, ASME PTC 46–1996, ISO 2314:2009(E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699–08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751–11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467–10 (incorporated by reference, see § 60.17).

* * * * *

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

* * * * *

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

* * * * *

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor.

* * * * *

■ 12. Table 1 to subpart TTTT is revised to read as follows:

Table 1 to Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Steam Generating Units and Integrated Gasification Combined Cycle Facilities That Commenced Construction After January 8, 2014, and Reconstruction or Modification After June 18, 2014

[*Note:* Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed steam generating unit or integrated gasification combined cycle (IGCC).	640 kg CO_2/MWh of gross energy output (1,400 lb CO_2/MWh-gross).
Reconstructed steam generating unit or IGCC that has base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.	910 kg CO_2/MWh of gross energy output (2,000 lb CO_2/MWh-gross).
Reconstructed steam generating unit or IGCC that has a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h).	820 kg CO_2/MWh of gross energy output (1,800 lb CO_2/MWh-gross).
Modified steam generating unit or IGCC	A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no lower than: (1) 820 kg CO_2/MWh of gross energy output (1,800 lb CO_2/MWh-gross) for units with a base load rating greater than 2,100 GJ/h (2,000 MMBtu/h); or (2) 910 kg CO_2/MWh of gross energy output (2,000 lb CO_2/MWh-gross) for units with a base load rating of 2,100 GJ/h (2,000 MMBtu/h) or less.

■ 13. Table 2 to subpart TTTT is revised to read as follows:

Table 2 to Subpart TTTT of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction After January 8, 2014, and Reconstruction After June 18, 2014 (Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[*Note:* Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis.	450 kg CO_2/MWh (1,000 lb CO_2/MWh) of gross energy output; or 470 kg CO_2/MWh (1,030 lb CO_2/MWh) of net energy output.

Affected EGU	CO_2 Emission standard
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis].	50 kg CO_2/GJ (120 lb CO_2/MMBtu) of heat input.
Newly constructed and reconstructed stationary combustion turbine that combusts 90% or less natural gas on a heat input basis on a 12-operating-month rolling average basis.	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525.

■ 14. Table 3 to subpart TTTT is revised to read as follows:

Table 3 to Subpart TTTT of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No.	
§ 60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods
§ 60.8(c)–(f)	Conducting performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements
§ 60.14	Modification	Yes (steam generating units and IGCC facilities). No (stationary combustion turbines).	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

■ 15. Add subpart TTTTa to read as follows:

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Applicability

Sec.

60.5508a What is the purpose of this subpart?
60.5509a Am I subject to this subpart?

Emissions Standards

60.5515a Which pollutants are regulated by this subpart?
60.5520a What CO_2 emissions standard must I meet?
60.5525a What are my general requirements for complying with this subpart?

Monitoring and Compliance Determination Procedures

60.5535a How do I monitor and collect data to demonstrate compliance?
60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

Notification, Reports, and Records

60.5550a What notifications must I submit and when?
60.5555a What reports must I submit and when?
60.5560a What records must I maintain?
60.5565a In what form and how long must I keep my records?

Other Requirements and Information

60.5570a What parts of the general provisions apply to my affected EGU?
60.5575a Who implements and enforces this subpart?
60.5580a What definitions apply to this subpart?

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)
Table 2 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Steam Generating Units or IGCC That Commenced Modification After May 23, 2023
Table 3 to Subpart TTTTa of Part 60—Applicability of Subpart A of Part 60 (General Provisions) to Subpart TTTTa

Subpart TTTTa—Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Applicability

§ 60.5508a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a coal-fired steam generating unit or integrated gasification combined cycle facility (IGCC) that commences modification after May 23, 2023. This subpart also establishes emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that commences construction or reconstruction after May 23, 2023. An affected coal-fired steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected electric generating unit (EGU).

§ 60.5509a Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit or IGCC that combusts coal and that commences modification after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 gigajoules per hour (GJ/h) (250 million British thermal units per hour (MMBtu/h)) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 megawatts (MW) of electricity to a utility power distribution system.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (8) of this section.

(1) Your EGU is a steam generating unit or IGCC whose annual net-electric sales have never exceeded one-third of its potential electric output or 219,000 megawatt-hour (MWh), whichever is greater, and is currently subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of deriving 50 percent or more of the heat input from non-fossil fuel at the base load rating and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO_2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO_2 emissions standards.

(8) Your EGU derives greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

Emission Standards

§ 60.5515a Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and Title V thresholds for greenhouse gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

§ 60.5520a What CO_2 emissions standard must I meet?

(a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO_2 in excess of the applicable CO_2 emission standard specified in table 1 to this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

(b) Except as specified in paragraphs (c) and (d) of this section, you must comply with the applicable gross or net energy output standard, and your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable gross or net energy output standard. For the remainder of this subpart (for sources that do not qualify

under paragraphs (c) and (d) of this section), where the term ''gross or net energy output'' is used, the term that applies to you is ''gross energy output.''

(c) As an alternative to meeting the requirements in paragraph (b) of this section, an owner or operator of a stationary combustion turbine may petition the Administrator in writing to comply with the alternate applicable net energy output standard. If the Administrator grants the petition, beginning on the date the Administrator grants the petition, the affected EGU must comply with the applicable net energy output-based standard included in this subpart. Your operating permit must include monitoring, recordkeeping, and reporting methodologies based on the applicable net energy output standard. For the remainder of this subpart, where the term ''gross or net energy output'' is used, the term that applies to you is ''net energy output.'' Owners or operators complying with the net output-based standard must petition the Administrator to switch back to complying with the gross energy output-based standard.

(d) Owners or operators of a stationary combustion turbine that maintain records of electric sales to demonstrate that the stationary combustion turbine is subject to a heat input-based standard in table 1 to this subpart that are only permitted to burn one or more uniform fuels, as described in paragraph (d)(1) of this section, are only subject to the monitoring requirements in paragraph (d)(1). Owners or operators of all other stationary combustion turbines that maintain records of electric sales to demonstrate that the stationary combustion turbines are subject to a heat input-based standard in table 1 are only subject to the requirements in paragraph (d)(2) of this section.

(1) Owners or operators of stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.,* uniform fuels) that result in a consistent emission rate of 69 kilograms per gigajoule (kg/GJ) (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under this subpart. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

(2) Owners or operators of stationary combustion turbines permitted to burn fuels that do not have a consistent chemical composition or that do not have an emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less (*e.g.,* non-uniform fuels such as residual oil and non-jet fuel kerosene) must follow the monitoring, recordkeeping, and reporting requirements necessary to complete the heat input-based calculations under this subpart.

§ 60.5525a What are my general requirements for complying with this subpart?

Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). For all other affected sources, compliance with the applicable CO_2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 to this subpart for the applicable CO_2 emission standards.

(a) You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. However, you must determine compliance with the emission standards only at the end of the applicable operating month, as provided in paragraph (a)(1) of this section.

(1) For each affected EGU subject to a CO_2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period.

(2) Consistent with § 60.5520a(d)(2), if your affected stationary combustion turbine is subject to an input-based CO_2 emissions standard, you must determine the total heat input in GJ or MMBtu from natural gas (HTIPng) and the total heat input from all other fuels combined (HTIPo) using one of the methods under § 60.5535a(d)(2). You must then use the following equation to determine the applicable emissions standard during the compliance period:

Equation 1 to Paragraph (a)(2)

$$CO_2\ emissions\ standard = \frac{(50 \times HTIP_{ng}) + (69 \times HTIP_O)}{HTIP_{ng} + HTIP_O}$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/GJ (or lb/MMBtu).

$HTIP_{ng}$ = the heat input in GJ (or MMBtu) from natural gas.

$HTIP_o$ = the heat input in GJ (or MMBtu) from all fuels other than natural gas.

50 = allowable emission rate in lb kg/GJ for heat input derived from natural gas (use 120 if electing to demonstrate compliance using lb CO_2/MMBtu).

69 = allowable emission rate in lb kg/GJ for heat input derived from all fuels other than natural gas (use 160 if electing to demonstrate compliance using lb CO_2/MMBtu).

(3) Owners/operators of a base load combustion turbine with a base load rating of less than 2,110 GJ/h (2,000 MMBtu/h) and/or an intermediate or base load combustion turbine burning fuels other than natural gas may elect to determine a site-specific emissions rate using one of the following equations. Combustion turbines co-firing hydrogen are not required to use the fuel adjustment parameter.

(i) For base load combustion turbines:

Equation 2 to Paragraph (a)(3)(i)

$$CO_2\ emissions\ standard = \left[BLER_L + \frac{BLER_S - BLER_L}{\mathrm{BLR}_L - \mathrm{BLR}_S} * (\mathrm{BLR}_L - BLR_A)\right] * \left[\frac{HIER_A}{HIER_{NG}}\right]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

$BLER_L$ = Base load emissions standard for natural gas-fired combustion turbines with base load ratings greater than 2,110 GJ/h (2,000 MMBtu/h). 360 kg CO_2/MWh-gross (800 lb CO_2/MWh-gross) or 370 kg CO_2/MWh-net (820 lb CO_2/MWh-net); 43 kg CO_2/MWh-gross (100 lb CO_2/MWh-gross) or 42 kg CO_2/MWh-net (97 lb CO_2/MWh-net); as applicable

$BLER_S$ = Base load emissions standard for natural gas-fired combustion turbines with a base load rating of 260 GJ/h (250 MMBtu/h). 410 kg CO_2/MWh-gross (900 lb CO_2/MWh-gross) or 420 kg CO_2/MWh-net (920 lb CO_2/MWh-net); 49 kg CO_2/MWh-gross (108 lb CO_2/MWh-gross) or 50 kg CO_2/MWh-net (110 lb CO_2/MWh-net); as applicable

BLR_L = Minimum base load rating of large combustion turbines 2,110 GJ/h (2,000 MMBtu/h)

BLR_S = Base load rating of smallest combustion turbine 260 GJ/h (250 MMBtu/h)

BLR_A = Base load rating of the actual combustion turbine in GJ/h (or MMBtu/h)

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2\ emissions\ standard\ = \mathrm{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. 520 kg/MWh-gross (1,150 lb CO_2/MWh-gross) or 530 kg CO_2/MWh-net (1,160 lb CO_2/MWh-net) or 450 kg/MWh-gross (1,100 lb CO_2/MWh-gross) or 460 kg CO_2/MWh-net (1,110 lb CO_2/MWh-net) as applicable

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

(b) At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this subpart, and inspection of the EGU.

(c) Within 30 days after the end of the initial compliance period (*i.e.,* no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 to this subpart, in accordance with the requirements in this subpart. The first operating month included in the initial 12-operating-month compliance period shall be determined as follows:

(1) For an affected EGU that commences commercial operation (as defined in 40 CFR 72.2), the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under:

(i) Section 60.5555a(c)(3)(i), for units subject to the Acid Rain Program; or

(ii) Section 60.5555a(c)(3)(ii), for units that are not in the Acid Rain Program.

(2) For a modified or reconstructed EGU that becomes subject to this subpart, the first month of the initial compliance period shall be the first operating month (as defined in § 60.5580a) after the calendar month in which emissions reporting is required to begin under § 60.5555a(c)(3)(iii).

(3) Emissions of CO_2 emitted by your affected facility and the output of the affected facility generated when it operated during a system emergency as defined in § 60.5580a are excluded for both applicability and compliance with the relevant standards of performance if you can sufficiently provide the documentation listed in § 60.5560a(i). The relevant standard of performance for affected EGUs that operate during a system emergency depends on the subcategory, as described in paragraphs (c)(3)(i) and (ii) of this section.

(i) For intermediate and base load combustion turbines that operate during a system emergency, you comply with the standard for low load combustion turbines specified in table 1 to this subpart.

(ii) For modified steam generating units, you must not discharge from the affected EGU any gases that contain CO_2 in excess of 230 lb CO_2/MMBtu.

Monitoring and Compliance Determination Procedures

§ 60.5535a How do I monitor and collect data to demonstrate compliance?

(a) Combustion turbines qualifying under § 60.5520a(d)(1) are not subject to any requirements in this section other than the requirement to maintain fuel purchase records for permitted fuel(s). If your combustion turbine uses non-uniform fuels as specified under § 60.5520a(d)(2), you must monitor heat input in accordance with paragraph (c)(1) of this section, and you must monitor CO_2 emissions in accordance with either paragraph (b), (c)(2), or (c)(5) of this section. For all other affected sources, you must prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/h), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see § 60.5555a(d) and (e)).

(b) You must determine the hourly CO_2 mass emissions in kg from your affected EGU(s) according to paragraphs (b)(1) through (5) of this section, or, if applicable, as provided in paragraph (c) of this section.

(1) For an affected EGU that combusts coal you must, and for all other affected EGUs you may, install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record hourly average CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere, and a flow monitoring system to measure hourly average stack gas flow rates, according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that your EGU does not use carbon separation (*e.g.,* carbon capture and storage), you may use data from a certified oxygen

(O2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). If you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, you may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(2) For each continuous monitoring system that you use to determine the CO_2 mass emissions, you must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part 75.

(3) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions rate from the affected EGU; you must not apply the bias adjustment factors described in Section 7.6.5 of appendix A to 40 CFR part 75 to the exhaust gas flow rate data.

(4) You must select an appropriate reference method to setup (characterize) the flow monitor and to perform the on-going RATAs, in accordance with 40 CFR part 75. If you use a Type-S pitot tube or a pitot tube assembly for the flow RATAs, you must calibrate the pitot tube or pitot tube assembly; you may not use the 0.84 default Type-S pitot tube coefficient specified in Method 2.

(5) Calculate the hourly CO_2 mass emissions (kg) as described in paragraphs (b)(5)(i) through (iv) of this section. Perform this calculation only for ''valid operating hours'', as defined in § 60.5540(a)(1).

(i) Begin with the hourly CO_2 mass emission rate (tons/h), obtained either from Equation F–11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a dry basis).

(ii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2.

(iii) Finally, multiply the result from paragraph (b)(5)(ii) of this section by 907.2 to convert it from tons of CO_2 to kg. Round off to the nearest kg.

(iv) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(c) If your affected EGU exclusively combusts liquid fuel and/or gaseous fuel, as an alternative to complying with paragraph (b) of this section, you may determine the hourly CO_2 mass emissions according to paragraphs (c)(1) through (4) of this section. If you use non-uniform fuels as specified in § 60.5520a(d)(2), you may determine CO_2 mass emissions during the compliance period according to paragraph (c)(5) of this section.

(1) If you are subject to an output-based standard and you do not install CEMS in accordance with paragraph (b) of this section, you must implement the applicable procedures in appendix D to 40 CFR part 75 to determine hourly EGU heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(2) For each measured hourly heat input rate, use Equation G–4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/h). You may determine site-specific carbon-based F-factors (Fc) using Equation F–7b in section 3.3.6 of appendix F to 40 CFR part 75, and you may use these Fc values in the emissions calculations instead of using the default Fc values in the Equation G–4 nomenclature.

(3) For each ''valid operating hour'' (as defined in § 60.5540(a)(1), multiply the hourly tons/h CO_2 mass emission rate from paragraph (c)(2) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 907.2 to convert from tons of CO_2 to kg. Round off to the nearest two significant figures.

(4) The hourly CO_2 tons/h values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6). You must use these data to calculate the hourly CO_2 mass emissions.

(5) If you operate a combustion turbine firing non-uniform fuels, as an alternative to following paragraphs (c)(1) through (4) of this section, you may determine CO_2 emissions during the compliance period using one of the following methods:

(i) Units firing fuel gas may determine the heat input during the compliance period following the procedure under § 60.107a(d) and convert this heat input to CO_2 emissions using Equation G–4 in appendix G to 40 CFR part 75.

(ii) You may use the procedure for determining CO_2 emissions during the compliance period based on the use of the Tier 3 methodology under 40 CFR 98.33(a)(3).

(d) Consistent with § 60.5520a, you must determine the basis of the emissions standard that applies to your affected source in accordance with either paragraph (d)(1) or (2) of this section, as applicable:

(1) If you operate a source subject to an emissions standard established on an output basis (*e.g.,* lb CO_2 per gross or net MWh of energy output), you must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the hourly gross electric output or net electric output, as applicable, from the affected EGU(s). These measurements must be performed using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). For a combined heat and power (CHP) EGU, as defined in § 60.5580a, you must also install, calibrate, maintain, and operate meters to continuously (*i.e.,* hour-by-hour) determine and record the total useful thermal output. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record the hourly steam flow rate, temperature, and pressure. Your plan shall ensure that you install, calibrate, maintain, and operate meters to record each component of the determination, hour-by-hour.

(2) If you operate a source subject to an emissions standard established on a heat-input basis (*e.g.,* lb CO_2/MMBtu) and your affected source uses non-uniform heating value fuels as delineated under § 60.5520a(d), you must determine the total heat input for each fuel fired during the compliance period in accordance with one of the following procedures:

(i) Appendix D to 40 CFR part 75;

(ii) The procedures for monitoring heat input under § 60.107a(d);

(iii) If you monitor CO_2 emissions in accordance with the Tier 3 methodology under 40 CFR 98.33(a)(3), you may convert your CO_2 emissions to heat input using the appropriate emission factor in table C–1 of 40 CFR part 98. If your fuel is not listed in table C–1, you must determine a fuel-specific carbon-based F-factor (Fc) in accordance with section 12.3.2 of EPA Method 19 of appendix A–7 to this part, and you must convert your CO_2 emissions to heat input using Equation G–4 in appendix G to 40 CFR part 75.

(e) Consistent with § 60.5520a, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load and/or direct mechanical energy contributed by each EGU to the electric generator. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the gross or net energy output. The Administrator may approve such alternate methods for apportioning the gross or net energy output whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(f) In accordance with §§ 60.13(g) and 60.5520a, if two or more affected EGUs that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack you must monitor hourly CO_2 mass emissions in accordance with one of the following procedures:

(1) If the EGUs are subject to the same emissions standard in table 1 to this subpart, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross or net energy output (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected EGUs and you must express the operating time as ''stack operating hours'' (as defined in 40 CFR 72.2). If you attain compliance with the applicable emissions standard in § 60.5520a at the common stack, each affected EGU sharing the stack is in compliance; or

(2) As an alternative to the requirements in paragraph (f)(1) of this section, or if the EGUs are subject to different emission standards in table 1 to this subpart, you must either:

(i) Monitor each EGU separately by measuring the hourly CO_2 mass emissions prior to mixing in the common stack or

(ii) Apportion the CO_2 mass emissions based on the unit's load contribution to the total load associated with the common stack and the appropriate F-factors. You may also elect to develop, demonstrate, and provide information satisfactory to the Administrator on alternate methods to apportion the CO_2 emissions. The Administrator may approve such alternate methods for apportioning the CO_2 emissions whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(g) In accordance with §§ 60.13(g) and 60.5520a if the exhaust gases from an affected EGU that implements the continuous emission monitoring provisions in paragraph (b) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), you must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in 40 CFR 72.2) at each stack or duct separately. In this case, you must determine compliance with the applicable emissions standard in table 1 or 2 to this subpart by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross or net energy output for the affected EGU.

§ 60.5540a How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) In accordance with § 60.5520a, if you are subject to an output-based emission standard or you burn non-uniform fuels as specified in § 60.5520a(d)(2), you must demonstrate compliance with the applicable CO_2 emission standard in table 1 to this subpart as required in this section. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs (a)(1) through (8) of this section to calculate the CO_2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (*e.g.,* either kg/MWh or kg/GJ). You must use the hourly CO_2 mass emissions calculated under § 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. Combustion turbines firing non-uniform fuels that contain CO_2 prior to combustion (*e.g.,* blast furnace gas or landfill gas) may sample the fuel stream to determine the quantity of CO_2 present in the fuel prior to combustion and exclude this portion of the CO_2 mass emissions from compliance determinations.

(1) Each compliance period shall include only ''valid operating hours'' in the compliance period, *i.e.,* operating hours for which:

(i) ''Valid data'' (as defined in § 60.5580a) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (kg) and, if a heat input-based standard applies, all the parameters used to determine total heat input for the hour are also obtained; and

(ii) The corresponding hourly gross or net energy output value is also valid data (Note: For hours with no useful output, zero is considered to be a valid value).

(2) You must exclude operating hours in which:

(i) The substitute data provisions of part 75 of this chapter are applied for any of the parameters used to determine the hourly CO_2 mass emissions or, if a heat input-based standard applies, for any parameters used to determine the hourly heat input;

(ii) An exceedance of the full-scale range of a continuous emission monitoring system occurs for any of the parameters used to determine the hourly CO_2 mass emissions or, if applicable, to determine the hourly heat input; or

(iii) The total gross or net energy output ($P_{gross/net}$) or, if applicable, the total heat input is unavailable.

(3) For each compliance period, at least 95 percent of the operating hours in the compliance period must be valid operating hours, as defined in paragraph (a)(1) of this section.

(4) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values from § 60.5535a for all of the valid operating hours in the compliance period.

(5) For each valid operating hour of the compliance period that was used in paragraph (a)(4) of this section to calculate the total CO_2 mass emissions, you must determine $P_{gross/net}$ (the corresponding hourly gross or net energy output in MWh) according to the procedures in paragraphs (a)(5)(i) and (ii) of this section, as appropriate for the type of affected EGU(s). For an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, if there is no gross or net electrical output, but there is mechanical or useful thermal output, you must still determine the gross or net energy output for that hour. In addition, for an operating hour in which a valid CO_2 mass emissions value is determined according to paragraph (a)(1)(i) of this section, but there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output, you must use that hour in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(i) Calculate $P_{gross/net}$ for your affected EGU using the following equation. All terms in the equation must be expressed in units of MWh. To convert each

hourly gross or net energy output (consistent with § 60.5520a) value reported under part 75 of this chapter to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(i)

$$P_{gross/net} = \frac{(Pe)_{ST}+(Pe)_{CT}+(Pe)_{IE}-(Pe)_{FW}-(Pe)_{A}}{TDF} + [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,] \text{ (Eq. 2)}$$

Where:

$P_{gross/net}$ = In accordance with § 60.5520a, gross or net energy output of your affected EGU for each valid operating hour (as defined in § 60.5540a(a)(1)) in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected EGU's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines, IGCC EGUs, or EGUs complying with a net energy output based standard.

$(Pe)_{A}$ = Electric energy used for any auxiliary loads in MWh. Not applicable for determining P_{gross}.

$(Pt)_{PS}$ = Useful thermal output of steam (measured relative to standard ambient temperature and pressure (SATP) conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(ii) of this section in MWh.

$(Pt)_{HR}$ = Non steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(Pt)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric Transmission and Distribution Factor of 0.95 for a combined heat and power affected EGU where at least on an annual basis 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, or 1.0 for all other affected EGUs.

(ii) If applicable to your affected EGU (for example, for combined heat and power), you must calculate (Pt)PS using the following equation:

Equation 2 to Paragraph (a)(5)(ii)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF} \text{ (Eq. 3)}$$

Where:

Q_m = Measured useful thermal output flow in kg (lb) for the operating hour.

H = Enthalpy of the useful thermal output at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in Joules per kilogram (J/kg) (or Btu/lb).

CF = Conversion factor of 3.6×10^9 J/MWh or 3.413×10^6 Btu/MWh.

(6) Sources complying with energy output-based standards must calculate the basis (*i.e.,* denominator) of their actual annual emission rate in accordance with paragraph (a)(6)(i) of this section. Sources complying with heat input based standards must calculate the basis of their actual annual emission rate in accordance with paragraph (a)(6)(ii) of this section.

(i) In accordance with § 60.5520a if you are subject to an output-based standard, you must calculate the total gross or net energy output for the affected EGU's compliance period by summing the hourly gross or net energy output values for the affected EGU that you determined under paragraph (a)(5) of this section for all of the valid operating hours in the applicable compliance period.

(ii) If you are subject to a heat input-based standard, you must calculate the total heat input for each fuel fired during the compliance period. The calculation of total heat input for each individual fuel must include all valid operating hours and must also be consistent with any fuel-specific procedures specified within your selected monitoring option under § 60.5535(d)(2).

(7) If you are subject to an output-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/MWh) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total gross or net energy output value calculated according to the procedures in paragraph (a)(6)(i) of this section. Round off the result to two significant figures if the calculated value is less than 1,000; round the result to three significant figures if the calculated value is greater than 1,000. If you are subject to a heat input-based standard, you must calculate the CO_2 mass emissions rate for the affected EGU(s) (kg/GJ or lb/MMBtu) by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(4) of this section by the total heat input calculated according to the procedures in paragraph (a)(6)(ii) of this section. Round off the result to two significant figures.

(8) You may exclude CO_2 mass emissions and output generated from your affected EGU from your calculations for hours during which the affected EGU operated during a system emergency, as defined in § 60.5580a, if you can provide the information listed in § 60.5560a(i). While operating during a system emergency, your compliance determination depends on your subcategory or unit type, as listed in paragraphs (a)(8)(i) through (ii) of this section.

(i) For affected EGUs in the intermediate or base load subcategory, your CO_2 emission standard while operating during a system emergency is the applicable emission standard for low load combustion turbines.

(ii) For affected modified steam generating units, your CO_2 emission standard while operating during a system emergency is 230 lb CO_2/MMBtu.

(b) In accordance with § 60.5520a, to demonstrate compliance with the applicable CO_2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO_2 mass emissions rate for your affected EGU must be determined

according to the procedures specified in paragraph (a)(1) through (8) of this section and must be less than or equal to the applicable CO_2 emissions standard in table 1 to this subpart, or the emissions standard calculated in accordance with § 60.5525a(a)(2).

(c) If you are the owner or operator of a new or reconstructed stationary combustion turbine operating in the base load subcategory, are installing add-on controls, and are unable to comply with the applicable Phase 2 CO_2 emission standard specified in table 1 to this subpart due to circumstances beyond your control, you may request a compliance date extension of no longer than one year beyond the effective date of January 1, 2032, and may only receive an extension once. The extension request must contain a demonstration of necessity that includes the following:

(1) A demonstration that your affected EGU cannot meet its compliance date due to circumstances beyond your control and you have taken all steps reasonably possible to install the controls necessary for compliance by the effective date up to the point of the delay. The demonstration shall:

(i) Identify each affected unit for which you are seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable CO_2 emission standard in table 1 to this subpart;

(iii) Describe and demonstrate all progress towards installing the controls and that you have acted consistently with achieving timely compliance, including;

(A) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable;

(B) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(iv) Identify the circumstances that are entirely beyond your control and that necessitate additional time to install the identified controls. This may include:

(A) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in table 1 to this subpart;

(B) Documentation of any permit delays; or

(C) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology;

(v) Identify a proposed compliance date no later than one year after the applicable compliance date listed in table 1 to this subpart.

(2) The Administrator is charged with approving or disapproving a compliance date extension request based on his or her written determination that your affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraph (c)(1) of this section. The following must be included:

(i) All documentation required as part of this extension must be submitted by you to the Administrator no later than 6 months prior to the applicable effective date for your affected EGU.

(ii) You must notify the Administrator of the compliance date extension request at the time of the submission of the request.

Notification, Reports, and Records

§ 60.5550a What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (3) and 60.19, as applicable to your affected EGU(s) (see table 3 to this subpart).

(b) You must prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs.

§ 60.5555a What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected EGUs that are required by § 60.5525a to conduct initial and on-going compliance determinations on a 12-operating-month rolling average basis, you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected EGU, you must submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (twelfth) operating month in a 12-operating-month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate for the compliance period according to the procedures in § 60.5540a. You must report the dates (month and year) of the first and twelfth operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter where your EGU violated the applicable CO_2 emission standard;

(iii) If one or more compliance periods end in the quarter and there are no violations for the affected EGU, you must include a statement indicating this in the report;

(iv) The percentage of valid operating hours in each 12-operating-month compliance period described in paragraph (a)(1) of this section (*i.e.,* the total number of valid operating hours (as defined in § 60.5540a(a)(1)) in that period divided by the total number of operating hours in that period, multiplied by 100 percent);

(v) Consistent with § 60.5520a, the CO_2 emissions standard (as identified in table 1 or 2 to this subpart) with which your affected EGU must comply; and

(vi) Consistent with § 60.5520a, an indication whether or not the hourly gross or net energy output ($P_{gross/net}$) values used in the compliance determinations are based solely upon gross electrical load.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Consistent with § 60.5520a, gross energy output or net energy output sold to an electric grid, as applicable to the units of your emission standard, over the four quarters of the calendar year; and

(ii) The potential electric output of the EGU.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c)(1) For affected EGUs under this subpart that are also subject to the Acid Rain Program, you must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(2) For affected EGUs under this subpart that are not in the Acid Rain Program, you must also meet the reporting requirements and submit

reports as required under subpart G of part 75 of this chapter, to the extent that those requirements and reports provide applicable data for the compliance demonstrations required under this subpart.

(3)(i) For all newly-constructed affected EGUs under this subpart that are also subject to the Acid Rain Program, you must begin submitting the quarterly electronic emissions reports described in paragraph (c)(1) of this section in accordance with 40 CFR 75.64(a), *i.e.,* beginning with data recorded on and after the earlier of:

(A) The date of provisional certification, as defined in 40 CFR 75.20(a)(3); or

(B) 180 days after the date on which the EGU commences commercial operation (as defined in 40 CFR 72.2).

(ii) For newly-constructed affected EGUs under this subpart that are not subject to the Acid Rain Program, you must begin submitting the quarterly electronic reports described in paragraph (c)(2) of this section, beginning with data recorded on and after the date on which reporting is required to begin under 40 CFR 75.64(a), if that date occurs on or after May 23, 2023.

(iii) For reconstructed or modified units, reporting of emissions data shall begin at the date on which the EGU becomes an affected unit under this subpart, provided that the ECMPS Client Tool is able to receive and process net energy output data on that date. Otherwise, emissions data reporting shall be on a gross energy output basis until the date that the Client Tool is first able to receive and process net energy output data.

(4) If any required monitoring system has not been provisionally certified by the applicable date on which emissions data reporting is required to begin under paragraph (c)(3) of this section, the maximum (or in some cases, minimum) potential value for the parameter measured by the monitoring system shall be reported until the required certification testing is successfully completed, in accordance with 40 CFR 75.4(j), 40 CFR 75.37(b), or section 2.4 of appendix D to part 75 of this chapter (as applicable). Operating hours in which CO_2 mass emission rates are calculated using maximum potential values are not ''valid operating hours'' (as defined in § 60.5540(a)(1)), and shall not be used in the compliance determinations under § 60.5540.

(d) For affected EGUs subject to the Acid Rain Program, the reports required under paragraphs (a) and (c)(1) of this section shall be submitted by:

(1) The person appointed as the Designated Representative (DR) under 40 CFR 72.20; or

(2) The person appointed as the Alternate Designated Representative (ADR) under 40 CFR 72.22; or

(3) A person (or persons) authorized by the DR or ADR under 40 CFR 72.26 to make the required submissions.

(e) For affected EGUs that are not subject to the Acid Rain Program, the owner or operator shall appoint a DR and (optionally) an ADR to submit the reports required under paragraphs (a) and (c)(2) of this section. The DR and ADR must register with the Clean Air Markets Division (CAMD) Business System. The DR may delegate the authority to make the required submissions to one or more persons.

(f) If your affected EGU captures CO_2 to meet the applicable emission standard, you must report in accordance with the requirements of 40 CFR part 98, subpart PP, and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from EPA pursuant to paragraph (g) of this section.

(g) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system, or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5560a What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b)(1) For affected EGUs subject to the Acid Rain Program, you must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) For affected EGUs that are not subject to the Acid Rain Program, you must also follow the recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter, to the extent that those records provide applicable data for the compliance determinations required under this subpart. Regardless of the prior sentence, at a minimum, the following records must be kept, as applicable to the types of continuous monitoring systems used to demonstrate compliance under this subpart:

(i) Monitoring plan records under 40 CFR 75.53(g) and (h);

(ii) Operating parameter records under 40 CFR 75.57(b)(1) through (4);

(iii) The records under 40 CFR 75.57(c)(2), for stack gas volumetric flow rate;

(iv) The records under 40 CFR 75.57(c)(3) for continuous moisture monitoring systems;

(v) The records under 40 CFR 75.57(e)(1), except for paragraph (e)(1)(x), for CO_2 concentration monitoring systems or O2 monitors used to calculate CO_2 concentration;

(vi) The records under 40 CFR 75.58(c)(1), specifically paragraphs (c)(1)(i), (ii), and (viii) through (xiv), for oil flow meters;

(vii) The records under 40 CFR 75.58(c)(4), specifically paragraphs (c)(4)(i), (ii), (iv), (v), and (vii) through (xi), for gas flow meters;

(viii) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (a)(1) through (12) and (15), for CEMS;

(ix) The quality-assurance records under 40 CFR 75.59(a), specifically paragraphs (b)(1) through (4), for fuel flow meters; and

(x) Records of data acquisition and handling system (DAHS) verification under 40 CFR 75.59(e).

(c) You must keep records of the calculations you performed to determine the hourly and total CO_2 mass emissions (tons) for:

(1) Each operating month (for all affected EGUs); and

(2) Each compliance period, including, each 12-operating-month compliance period.

(d) Consistent with § 60.5520a, you must keep records of the applicable data recorded and calculations performed that you used to determine your affected EGU's gross or net energy output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in table 1 or 2 to this subpart.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h) For stationary combustion turbines, you must keep records of electric sales to determine the applicable subcategory.

(i) You must keep the records listed in paragraphs (i)(1) through (3) of this section to demonstrate that your affected facility operated during a system emergency.

(1) Documentation that the system emergency to which the affected EGU was responding was in effect from the entity issuing the alert and documentation of the exact duration of the system emergency;

(2) Documentation from the entity issuing the alert that the system emergency included the affected source/region where the affected facility was located; and

(3) Documentation that the affected facility was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/Regional Transmission Organization.

§ 60.5565a In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of conclusion of each compliance period.

(c) You must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570a What parts of the general provisions apply to my affected EGU?

Notwithstanding any other provision of this chapter, certain parts of the general provisions in §§ 60.1 through 60.19, listed in table 3 to this subpart, do not apply to your affected EGU.

§ 60.5575a Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or Tribal agency. If the Administrator has delegated authority to your state, local, or Tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or Tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or Tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or Tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subpart A (general provisions) of this part.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating. Actual and potential heat input derived from non-combustion sources (*e.g.,* solar thermal) are not included when calculating the annual capacity factor.

Base load combustion turbine means a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis plus the maximum amount of heat input derived from non-combustion source (*e.g.,* solar thermal), as determined by the physical design and characteristics of the EGU at International Organization for Standardization (ISO) conditions. For a stationary combustion turbine, *base load rating* includes the heat input from duct burners.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite in ASTM D388–99R04 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including, but not limited to, solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Coal-fired Electric Generating Unit means a steam generating unit or integrated gasification combined cycle unit that combusts coal on or after the date of modification or at any point after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit (HRSG) to generate additional electricity.

Combined heat and power unit or *CHP unit, (*also known as ''cogeneration'') means an electric generating unit that simultaneously produces both electric (or mechanical) and useful thermal output from the same primary energy source.

Design efficiency means the rated overall net efficiency (*e.g.,* electric plus useful thermal output) on a higher heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (*e.g.,* CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22–2014, ASME PTC 46–1996, ISO 2314:2009 (E) (all incorporated by reference, see § 60.17), or an alternative approved by the Administrator. When determining the design efficiency, the output of integrated equipment and energy storage are included.

Distillate oil means fuel oils that comply with the specifications for fuel oil numbers 1 and 2, as defined in ASTM D396–98 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined in ASTM D975–08a (incorporated by reference, see § 60.17); kerosene, as defined in ASTM D3699–08 (incorporated by reference, see § 60.17); biodiesel as defined in ASTM D6751–11b (incorporated by reference, see § 60.17); or biodiesel blends as defined in ASTM D7467–10 (incorporated by reference, see § 60.17).

Electric Generating units or EGU means any steam generating unit, IGCC unit, or stationary combustion turbine that is subject to this rule (*i.e.,* meets the applicability criteria).

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means an EGU in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the EGU during operation.

Intermediate load combustion turbine means a stationary combustion turbine that supplies more than 20 percent but less than or equal to 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis.

Mechanical output means the useful mechanical energy that is not used to operate the affected EGU(s), generate electricity and/or thermal energy, or to enhance the performance of the affected EGU. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Net-electric output means the amount of gross generation the generator(s) produces (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net-electric sales means:

(1) The gross electric sales to the utility power distribution system minus purchased power; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating month basis, the gross electric sales to the utility power distribution system minus the applicable percentage of purchased power of the thermal host facility or facilities. The applicable percentage of purchase power for CHP facilities is determined based on the percentage of the total thermal load of the host facility supplied to the host facility by the CHP facility. For example, if a CHP facility serves 50 percent of a thermal host's thermal demand, the owner/operator of the CHP facility would subtract 50 percent of the thermal host's electric purchased power when calculating net-electric sales.

(3) Electricity supplied to other facilities that produce electricity to offset auxiliary loads are included when calculating net-electric sales.

(4) Electric sales during a system emergency are not included when calculating net-electric sales.

Net energy output means:

(1) The net electric or mechanical output from the affected EGU plus 100 percent of the useful thermal output; or

(2) For combined heat and power facilities, where at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating-month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output.

Operating month means a calendar month during which any fuel is combusted in the affected EGU at any time.

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Potential electric output means the base load rating design efficiency at the maximum electric production rate (*e.g.,* CHP units with condensing steam turbines will operate at maximum electric production) multiplied by the base load rating (expressed in MMBtu/

h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (*e.g.,* a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12-month potential electric output capacity).

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, (*e.g.,* onsite photovoltaics), integrated energy storage (*e.g.,* onsite batteries), heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment.

System emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2 or its successor.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to part 75 of this chapter. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.5, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D to 40 CFR part 75), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Violation means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in table 1 to this subpart.

TABLE 1 TO SUBPART TTTTA OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STATIONARY COMBUSTION TURBINES THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 23, 2023 (GROSS OR NET ENERGY OUTPUT-BASED STANDARDS APPLICABLE AS APPROVED BY THE ADMINISTRATOR)

[Note: Numerical values of 1,000 or greater have a minimum of 3 significant figures and numerical values of less than 1,000 have a minimum of 2 significant figures]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
	For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

TABLE 2 TO SUBPART TTTTA OF PART 60—CO_2 EMISSION STANDARDS FOR AFFECTED STEAM GENERATING UNITS OR IGCC THAT COMMENCED MODIFICATION AFTER MAY 23, 2023

Affected EGU	CO_2 Emission standard
Modified coal-fired steam generating unit.	A unit-specific emissions standard determined by an 88.4 percent reduction in the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification).

TABLE 3 TO SUBPART TTTTA OF PART 60—APPLICABILITY OF SUBPART A OF PART 60 (GENERAL PROVISIONS) TO SUBPART TTTTA

General provisions citation	Subject of citation	Applies to subpart TTTTa	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580a.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§ 60.5	Determination of construction or modification.	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping.	Yes	Only the requirements to submit the notifications in § 60.7(a)(1) and (3) and to keep records of malfunctions in § 60.7(b), if applicable.
§ 60.8(a)	Performance tests	No..	
§ 60.8(b)	Performance test method alternatives.	Yes	Administrator can approve alternate methods.
§ 60.8(c)–(f)	Conducting performance tests.	No..	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No..	
§ 60.12	Circumvention	Yes.	
§ 60.13 (a)–(h), (j)	Monitoring requirements	No	All monitoring is done according to part 75.
§ 60.13 (i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§ 60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)..	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	No..	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements.	No..	
§ 60.19	General notification and reporting requirements.	Yes	Does not apply to notifications under § 75.61 or to information reported through ECMPS.

Subpart UUUUa—[Reserved]

■ 16. Remove and reserve subpart UUUUa.

■ 17. Add subpart UUUUb to read as follows:

Sec.

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

Introduction

60.5700b What is the purpose of this subpart?
60.5705b Which pollutants are regulated by this subpart?
60.5710b Am I affected by this subpart?
60.5715b What is the review and approval process for my State plan?
60.5720b What if I do not submit a State plan or my State plan is not approvable?
60.5725b In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?
60.5730b Is there an approval process for a negative declaration letter?

State Plan Requirements

60.5740b What must I include in my federally enforceable State plan?
60.5775b What standards of performance must I include in my State plan?
60.5780b What compliance dates and compliance periods must I include in my State plan?
60.5785b What are the timing requirements for submitting my State plan?
60.5790b What is the procedure for revising my State plan?
60.5795b Commitment to review emission guidelines for coal-fired affected EGUs

Applicability of State Plans to Affected EGUs

60.5840b Does this subpart directly affect EGU owners or operators in my State?
60.5845b What affected EGUs must I address in my State plan?
60.5850b What EGUs are excluded from being affected EGUs?

Recordkeeping and Reporting Requirements

60.5860b What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my State plan for affected EGUs?
60.5865b What are my recordkeeping requirements?
60.5870b What are my reporting and notification requirements?

60.5875b How do I submit information required by these emission guidelines to the EPA?
60.5876b What are the recordkeeping and reporting requirements for EGUs that have committed to permanently cease operations by January 1, 2032?

Definitions

60.5880b What definitions apply to this subpart?

Subpart UUUUb—Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units

Introduction

§ 60.5700b What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for State plans that establish standards of performance limiting greenhouse gas (GHG) emissions from an affected steam generating unit. An affected steam generating unit shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with section 111(d) of the Clean Air Act and subpart Ba of this part. State plans under the emission guidelines in this subpart are also subject to the requirements of subpart Ba. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or Ba of this part, the requirements of this subpart shall apply.

§ 60.5705b Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases (GHG). The emission guidelines for greenhouse gases established in this subpart are expressed as carbon dioxide (CO_2) emission performance rates.

(b) PSD and Title V Thresholds for Greenhouse Gases.

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from facilities regulated in the State plan, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from facilities regulated in the State plan, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from facilities regulated in the State plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to GHG emissions from facilities regulated in the State plan, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

§ 60.5710b Am I affected by this subpart?

(a) If you are the Governor of a State in the contiguous United States with one or more affected EGUs that must be addressed in your State plan as indicated in § 60.5845b, you must submit a State plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. If you are the Governor of a State in the contiguous United States with no affected EGUs, or if all EGUs in your State are excluded from being affected EGUs per § 60.5850b, you must submit a negative declaration letter in place of the State plan.

(b) If you are a coal-fired steam generating unit that has demonstrated that it plans to permanently cease operation prior to January 1, 2032, consistent with § 60.5740b(a)(9)(ii), and that would be an affected EGU under these emissions guidelines but for § 60.5850b(k), you must comply with § 60.5876b.

§ 60.5715b What is the review and approval process for my State plan?

(a) The EPA will determine the completeness of your State plan submission according to § 60.27a(g). The timeline for completeness determinations is provided in § 60.27a(g)(1).

(b) The EPA will act on your State plan submission according to § 60.27a. The Administrator will have 12 months after the date the final State plan or State plan revision (as allowed under § 60.5790b) is found to be complete to fully approve, partially approve, conditionally approve, partially disapprove, and/or fully disapprove such State plan or revision or each portion thereof.

§ 60.5720b What if I do not submit a State plan or my State plan is not approvable?

(a) If you do not submit an approvable State plan the EPA will develop a Federal plan for your State according to § 60.27a. The Federal plan will implement the emission guidelines contained in this subpart. Owners and operators of affected EGUs not covered by an approved State plan must comply with a Federal plan implemented by the EPA for the State.

(b) After a Federal plan has been implemented in your State, it will be withdrawn when your State submits, and the EPA approves, a State plan replacing the relevant portion(s) of the Federal plan.

§ 60.5725b In lieu of a State plan submittal, are there other acceptable option(s) for a State to meet its CAA section 111(d) obligations?

A State may meet its CAA section 111(d) obligations only by submitting a State plan or a negative declaration letter (if applicable).

§ 60.5730b Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, consistent with the electronic submission requirements in § 60.5875b, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014, reconstruction on or before June 18, 2014, or modification on or before May 23, 2023, is found in your State, you will be found to have failed to submit a State plan as required, and a Federal plan implementing the emission guidelines contained in this subpart, when promulgated by the EPA, will apply to that affected EGU until you submit, and the EPA approves, a State plan.

State Plan Requirements

§ 60.5740b What must I include in my federally enforceable State plan?

(a) You must include the components described in paragraphs (a)(1) through (13) of this section in your State plan submittal. The final State plan must meet the requirements and include the information required under § 60.5775b and must also meet any administrative and technical completeness criteria listed in § 60.27a(g)(2) and (3) that are not otherwise specifically enumerated here.

(1) *Identification of affected EGUs.* Consistent with § 60.25a(a), you must identify the affected EGUs covered by

your State plan and all affected EGUs in your State that meet the applicability criteria in § 60.5845b. You must also identify the subcategory into which you have classified each affected EGU. States must subcategorize affected EGUs into one of the following subcategories:

(i) *Long-term coal-fired steam generating units,* consisting of coal-fired steam generating units that are not medium-term coal-fired steam generating units and do not plan to permanently cease operation before January 1, 2039.

(ii) *Medium-term coal-fired steam generating units,* consisting of coal-fired steam generating units that have elected to commit to permanently cease operations by a date after December 31, 2031, and before January 1, 2039.

(iii) *Base load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.

(iv) *Intermediate load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.

(v) *Low load oil-fired steam generating units,* consisting of oil-fired steam generating units with an annual capacity factor less than 8 percent.

(vi) *Base load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 45 percent.

(vii) *Intermediate load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor greater than or equal to 8 percent and less than 45 percent.

(viii) *Low load natural gas-fired steam generating units,* consisting of natural gas-fired steam generating units with an annual capacity factor less than 8 percent.

(2) *Inventory of Data from Affected EGUs.* You must include an inventory of the following data from the affected EGUs:

(i) The nameplate capacity of the affected EGU, as defined in § 60.5880b.

(ii) The base load rating of the affected EGU, as defined in § 60.5880b.

(iii) The data within the continuous 5-year period immediately prior to May 9, 2024 including:

(A) The sum of the CO_2 emissions during each quarter in the 5-year period.

(B) For affected EGUs in all subcategories except the low load natural gas- and oil-fired subcategories, the sum of the gross energy output during each quarter in the 5-year period; for affected EGUs in the low load natural gas- and oil-fired subcategories, the sum of the heat input during each quarter in the 5-year period.

(C) The heat input for each fuel type combusted during each quarter in the 5-year period.

(D) The start date and end date of the most representative continuous 8-quarter period used to determine the baseline of emission performance under § 60.5775b(d), the sum of the CO_2 mass emissions during that period, the sum of the gross energy output or, for affected EGUs in the low load natural gas-fired subcategory or low load oil-fired subcategory, the sum of the heat input during that period, and sum of the heat input for each fuel type combusted during that period.

(3) *Standards of Performance.* You must include all standards of performance for each affected EGU according to § 60.5775b. Standards of performance must be established at a level of performance that does not exceed the level calculated through the use of the methods described in § 60.5775b(b), unless a State establishes a standard of performance pursuant to § 60.5775b(e).

(4) *Requirements related to Subcategory Applicability.* (i) You must include the following enforceable requirements to establish an affected EGU's applicability for each of the following subcategories:

(A) For medium-term coal-fired steam generating units, you must include a requirement to permanently cease operations by a date after December 31, 2031, and before January 1, 2039.

(B) For steam generating units that meet the definition of natural gas- or oil-fired, and that either retain the capability to fire coal after May 9, 2024, that fired any coal during the 5-year period prior to that date, or that will fire any coal after that date and before January 1, 2030, you must include a requirement to remove the capability to fire coal before January 1, 2030.

(C) For each affected EGU, you must also estimate coal, oil, and natural gas usage by heat input for the first 3 calendar years after January 1, 2030.

(D) For affected EGUs that plan to permanently cease operation, you must include a requirement that each such affected EGU comply with applicable State and Federal requirements for permanently ceasing operation, including removal from its respective State's air emissions inventory and amending or revoking all applicable permits to reflect the permanent shutdown status of the EGU.

(5) *Increments of Progress.* You must include in your State plan legally enforceable increments of progress as required elements for affected EGUs in the long-term coal-fired steam generating unit and medium-term coal-fired steam generating unit subcategories.

(i) For affected EGUs in the long-term coal-fired steam generating unit subcategory using carbon capture to meet their applicable standard of performance and affected EGUs in the medium-term coal-fired steam generating unit subcategory using natural gas co-firing to meet their applicable standard of performance, State plans must assign calendar-date deadlines to each of the increments of progress described in subsection (a)(5)(i) and meet the website reporting obligations of subsection (a)(5)(iii):

(A) Submittal of a final control plan for the affected EGU to the appropriate air pollution control agency. The final control plan must be consistent with the subcategory declaration for each affected EGU in the State plan.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including a feasibility and/or front-end engineering and design (FEED) study.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, the final control plan must include supporting analysis for the affected EGU's control strategy, including the design basis for modifications at the facility, the anticipated timeline to achieve full compliance, and the benchmarks the facility anticipates along the way.

(B) Completion of awarding of contracts. The owner or operator of an affected EGU can demonstrate compliance with this increment of progress by submitting sufficient evidence that the appropriate contracts have been awarded.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, awarding of contracts for boiler modifications, or issuance of orders for the purchase of component parts to accomplish boiler modifications.

(C) Initiation of on-site construction or installation of emission control equipment or process change.

(1) For each affected unit in the long-term coal-fired steam generating unit

subcategory, initiation of on-site construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, initiation of on-site construction or installation of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(D) Completion of on-site construction or installation of emission control equipment or process change.

(1) For each affected unit in the long-term coal-fired steam generating unit subcategory, completion of on-site construction or installation of emission control equipment or process change required to achieve 90 percent carbon capture on an annual basis.

(2) For each affected unit in the medium-term coal-fired steam generating unit subcategory, completion of on-site construction of any boiler modifications necessary to enable natural gas co-firing at a level of 40 percent on an annual average basis.

(E) Commencement of permitting actions related to pipeline construction. The owner or operator of an affected EGU must demonstrate that they have commenced permitting actions by a date specified in the State plan. Evidence in support of the demonstration must include pipeline planning and design documentation that informed the permitting process, a complete list of pipeline-related permitting applications, including the nature of the permit sought and the authority to which each permit application was submitted, an attestation that the list of pipeline-related permits is complete with respect to the authorizations required to operate each affected unit at full compliance with the standard of performance, and a timeline to complete all pipeline permitting activities.

(1) For affected units in the long-term coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts CCS to meet the standard of performance and ensure timely completion of CCS-related pipeline infrastructure.

(2) For affected units in the medium-term coal-fired steam generating unit subcategory, this increment of progress applies to each affected EGU that adopts natural gas co-firing to meet the standard of performance and ensures timely completion of any pipeline infrastructure needed to transport natural gas to designated facilities.

(F) For each affected unit in the long-term coal-fired steam generating unit subcategory, a report identifying the geographic location where CO_2 will be injected underground, how the CO_2 will be transported from the capture location to the storage location, and the regulatory requirements associated with the sequestration activities, as well as an anticipated timeline for completing related permitting activities.

(G) Compliance with the standard of performance as follows:

(1) For each affected unit in the medium-term coal-fired subcategory, by January 1, 2030.

(2) For each affected unit in the long-term coal-fired steam generating subcategory, by January 1, 2032.

(ii) For any affected unit in the long-term coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than CCS or in the medium-term coal-fired steam generating unit subcategory that will meet its applicable standard of performance using a control other than natural gas co-firing:

(A) The State plan must include appropriate increments of progress consistent with 40 CFR 60.21a(h) specific to the affected unit's control strategy.

(1) The increment of progress corresponding to 40 CFR 60.21a(h)(1) must be assigned the earliest calendar date among the increments.

(2) The increment of progress corresponding to 40 CFR 60.21a(h)(5) must be assigned calendar dates as follows: for affected EGUs in the long-term coal-fired steam generating subcategory, no later than January 1, 2032; and for affected EGUs in the medium-term coal-fired steam generating subcategory, no later than January 1, 2030.

(iii) The owner or operator of the affected EGU must post within 30 business days of the State plan submittal a description of the activities or actions that constitute the increments of progress and the schedule for achieving the increments of progress on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10). As the calendar dates for each increment of progress occurs, the owner or operator of the affected EGU must post within 30 business days any documentation necessary to demonstrate that each increment of progress has been met on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10).

(iv) You must include in your State plan a requirement that the owner or operator of each affected EGU shall report to the State regulatory agency any deviation from any federally enforceable State plan increment of progress within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. This report must explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. You must also include in your State plan a requirement that the owner or operator of the affected EGU to post a report of any deviation from any federally enforceable increment of progress on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10) within 30 business days.

(6) *Reporting Obligations and Milestones for Affected EGUs that Have Demonstrated They Plan to Permanently Cease Operations.* You must include in your State plan legally enforceable reporting obligations and milestones for affected EGUs in the medium-term coal-fired steam generating unit (§ 60.5740b(a)(1)(ii)) subcategory, and for affected EGUs that invoke RULOF based on a unit's remaining useful life according to paragraphs (a)(6)(i) through (v) of this section:

(i) Five years before the date the affected EGU permanently ceases operations (either the date used to determine the applicable subcategory under these emission guidelines or the date used to invoke RULOF based on remaining useful life) or 60 days after State plan submission, whichever is later, the owner or operator of the affected EGU must submit an Initial Milestone Report to the applicable air pollution control agency that includes the information in paragraphs (a)(6)(i)(A) through (D) of this section:

(A) A summary of the process steps required for the affected EGU to permanently cease operations by the date included in the State plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit.

(B) A list of key milestones that will be used to assess whether each process step has been met, and calendar day deadlines for each milestone. These milestones must include at least the initial notice to the relevant reliability authority or authorities of an EGU's deactivation date and submittal of an official retirement filing with the EGU's relevant reliability authority or authorities.

(C) An analysis of how the process steps, milestones, and associated timelines included in the Milestone

Report compare to the timelines of similar EGUs within the State that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines.

(D) Supporting regulatory documents, which include those listed in paragraphs (a)(6)(i)(D)(*1*) through (*3*) of this section:

(1) Any correspondence and official filings with the relevant Regional Transmission Organization (RTO), Independent System Operator, Balancing Authority, Public Utilities Commission (PUC), or other applicable authority;

(2) Any deactivation-related reliability assessments conducted by the RTO or Independent System Operator;

(3) Any filings with the United States Securities and Exchange Commission or notices to investors, including but not limited to, those listed in paragraphs (a)(6)(i)(D)(*3*)(*i*) through (*v*) of this section.

(i) References in forms 10–K and 10–Q, in which the plans for the EGU are mentioned;

(ii) Any integrated resource plans and PUC orders approving the EGU's deactivation;

(iii) Any reliability analyses developed by the RTO, Independent System Operator, or relevant reliability authority in response to the EGU's deactivation notification;

(iv) Any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and

(v) Any notification to or from an RTO, Independent System Operator, or Balancing Authority altering the timing of deactivation for the EGU.

(ii) For each of the remaining years prior to the date by which an affected EGU has committed to permanently cease operations that is included in the State plan, the owner or operator of the affected EGU must submit an annual Milestone Status Report that includes the information in paragraphs (a)(6)(ii)(A) and (B) of this section:

(A) Progress toward meeting all milestones identified in the Initial Milestone Report, described in § 60.5740b(a)(6)(i); and

(B) Supporting regulatory documents and relevant SEC filings, including correspondence and official filings with the relevant RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority to demonstrate compliance with or progress toward all milestones.

(iii) No later than six months from the date the affected EGU permanently ceases operations (either the date used to determine the applicable subcategory under these emission guidelines or the date used to invoke RULOF based on remaining useful life), the owner or operator of the affected EGU must submit a Final Milestone Status Report. This report must document any actions that the EGU has taken subsequent to ceasing operation to ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(iv) The owner or operator of the affected EGU must post their Initial Milestone Report, as described in paragraph (a)(6)(i) of this section; annual Milestone Status Reports, as described in paragraph (a)(6)(ii) of this section; and Final Milestone Status Report, as described in paragraph (a)(6)(iii) of this section; including the schedule for achieving milestones and any documentation necessary to demonstrate that milestones have been achieved, on the Carbon Pollution Standards for EGUs website required by paragraph (a)(10) of this section within 30 business days of being filed.

(v) You must include in your State plan a requirement that the owner or operator of each affected EGU shall report to the State regulatory agency any deviation from any federally enforceable State plan reporting milestone within 30 business days after the owner or operator of the affected EGU knew or should have known of the event. This report must explain the cause or causes of the deviation and describe all measures taken or to be taken by the owner or operator of the EGU to cure the reported deviation and to prevent such deviations in the future, including the timeframes in which the owner or operator intends to cure the deviation. You must also include in your State plan a requirement that the owner or operator of the affected EGU to post a report of any deviation from any federally enforceable reporting milestone on the Carbon Pollution Standards for EGUs website required by § 60.5740b(a)(10) within 30 business days.

(7) *Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected EGU.* You must include in your State plan all applicable monitoring, reporting and recordkeeping requirements, including initial and ongoing quality assurance and quality control procedures, for each affected EGU and the requirements must be consistent with or no less stringent than the requirements specified in § 60.5860b.

(8) *State reporting.* You must include in your State plan a description of the process, contents, and schedule for State reporting to the EPA about State plan implementation and progress.

(9) *Specific requirements for existing coal-fired steam generating EGUs.* Your State plan must include the requirements in paragraphs (a)(9)(i) through (iii) of this section specifically for existing coal-fired steam generating EGUs:

(i) Your State plan must require that any existing coal-fired steam-generating EGU shall operate only subject to a standard of performance pursuant to § 60.5775b or under an exemption of applicability provided under § 60.5850b (including any extension of the date by which an EGU has committed to cease operating pursuant to the reliability assurance mechanism, described in paragraph (a)(13) of this section).

(ii) You must include a list of the coal-fired steam generating EGUs that are existing sources at the time of State plan submission and that plan to permanently cease operation before January 1, 2032, and the calendar dates by which they have committed to cease operating.

(iii) The State plan must provide that an existing coal-fired steam generating EGU operating past the date listed in the State plan pursuant to paragraph (a)(9)(ii) of this section is in violation of that State plan, except to the extent the existing coal-fired steam generating EGU has received an extension of its date for ceasing operation pursuant to the reliability assurance mechanism, described in paragraph (a)(13) of this section.

(10) *Carbon Pollution Standards for EGUs Websites.* You must require in your State plan that owners or operators of affected EGUs establish a publicly accessible ''Carbon Pollution Standards for EGUs Website'' and that they post relevant documents to this website. You must require in your State plan that owners or operators of affected EGUs post their subcategory designations and compliance schedules as well as any emissions data and other information needed to demonstrate compliance with a standard of performance to this website in a timely manner. This information includes, but is not limited to, emissions data and other information relevant to determining compliance with applicable standards of performance, information relevant to the designation and determination of compliance with increments of progress and reporting obligations including milestones for affected EGUs that plan to permanently cease operations, and any extension requests made and

granted pursuant to the compliance date extension mechanism or the reliability assurance mechanism. Data should be available in a readily downloadable format. In addition, you must establish a website that displays the links to these websites for all affected EGUs in your State plan.

(11) *Compliance Date Extension.* You may include in your State plan provisions allowing for a compliance date extension for owners or operators of affected EGU(s) that are installing add-on controls and that are unable to meet the applicable standard of performance by the compliance date specified in § 60.5740b(a)(4)(i) due to circumstances beyond the owner or operator's control. Such provisions may allow an owner or operator of an affected EGU to request an extension of no longer than one year from the specified compliance date and may only allow the owner or operator to receive an extension once. The optional State plan mechanism must provide that an extension request contains a demonstration of necessity that includes the following:

(i) A demonstration that the owner or operator of the affected EGU cannot meet its compliance date due to circumstances beyond the owner or operator's control and that the owner or operator has met all relevant increments of progress and otherwise taken all steps reasonably possible to install the controls necessary for compliance by the specified compliance date up to the point of the delay. The demonstration shall:

(A) Identify each affected unit for which the owner or operator is seeking the compliance extension;

(B) Identify and describe the controls to be installed at each affected unit to comply with the applicable standard of performance pursuant to § 60.5775b;

(C) Describe and demonstrate all progress towards installing the controls and that the owner or operator has itself acted consistent with achieving timely compliance, including:

(1) Any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable; and

(2) Any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permit authority identifying its anticipated timeframe for issuance of such permit(s).

(D) Identify the circumstances that are entirely beyond the owner or operator's control and that necessitate additional time to install the identified controls. This may include:

(1) Information gathered from control technology vendors or engineering firms demonstrating that the necessary controls cannot be installed or started up by the applicable compliance date listed in § 60.5740b(a)(4)(i);

(2) Documentation of any permit delays; or

(3) Documentation of delays in construction or permitting of infrastructure (*e.g.,* CO_2 pipelines) that is necessary for implementation of the control technology;

(E) Identify a proposed compliance date no later than one year after the applicable compliance date listed in § 60.5740b(a)(4)(i) and, if necessary, updated calendar dates for the increments of progress that have not yet been met.

(ii) The State air pollution control agency is charged with approving or disapproving a compliance date extension request based on its written determination that the affected EGU has or has not made each of the necessary demonstrations and provided all of the necessary documentation according to paragraphs (a)(11)(i)(A) through (E) of this section. The following provisions for approval must be included in the mechanism:

(A) All documentation required as part of this extension must be submitted by the owner or operator of the affected EGU to the State air pollution control agency no later than 6 months prior to the applicable compliance date for that affected EGU.

(B) The owner or operator of the affected EGU must notify the relevant EPA Regional Administrator of their compliance date extension request at the time of the submission of the request.

(C) The owner or operator of the affected EGU must post their application for the compliance date extension request to the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10), when they submit the request to the State air pollution control agency.

(D) The owner or operator of the affected EGU must post the State's determination on the compliance date extension request to the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10), upon receipt of the determination and, if the request is approved, update the information on the website related to the compliance date and increments of progress dates within 30 days of the receipt of the State's approval.

(12) *Short-Term Reliability Mechanism.* You may include in your State plan provisions for a short-term reliability mechanism for affected EGUs in your State that operate during a system emergency, as defined in § 60.5880b. Such a mechanism must include the components listed in paragraphs (a)(12)(i) through (vi) of this section.

(i) A requirement that the short-term reliability mechanism is available only during system emergencies as defined in § 60.5880b. The State plan must identify the entity or entities that are authorized to issue system emergencies for the State.

(ii) A provision that, for the duration of a documented system emergency, an impacted affected EGU may comply with an emission limitation corresponding to its baseline emission performance rate, as calculated under § 60.5775b(d), in lieu of its otherwise applicable standard of performance. The State plan must clearly identify the alternative emission limitation that corresponds to the affected EGU's baseline emission rate and include it as an enforceable emission limitation that may be applied only during periods of system emergency.

(iii) A requirement that an affected EGU impacted by the system emergency and complying with an alternative emission limitation must provide documentation, as part of its compliance demonstration, of the system emergency according to (a)(12)(iii)(A) through (D) of this section and that it was impacted by that system emergency.

(A) Documentation that the system emergency was in effect from the entity issuing the system emergency and documentation of the exact duration of the event;

(B) Documentation from the entity issuing the system emergency that the system emergency included the affected source/region where the unit was located;

(C) Documentation that the source was instructed to increase output beyond the planned day-ahead or other near-term expected output and/or was asked to remain in operation outside of its scheduled dispatch during emergency conditions from a Reliability Coordinator, Balancing Authority, or Independent System Operator/RTO; and

(D) Data collected during the event including the sum of the CO_2 emissions, the sum of the gross energy output, and the resulting CO_2 emissions performance rate.

(iv) A requirement to document the hours an affected EGU operated under a system emergency and the enforceable emission limitation, whether the applicable standard of performance or

the alternative emission limitation, under which that affected EGU operated during those hours.

(v) A provision that, for the purpose of demonstrating compliance with the applicable standard of performance, the affected EGU would comply with its baseline emissions rate as calculated under § 60.5775b(d) in lieu of its otherwise applicable standard of performance for the hours of operation that correspond to the duration of the event.

(vi) The inclusion of provisions defining the short-term reliability mechanism must be part of the public comment process as part of the State plan's development.

(13) *Reliability Assurance Mechanism.* You may include provisions for a reliability assurance mechanism in your State plan. If included, such provisions would allow for one extension, not to exceed 12-months of the date by which an affected EGU has committed to permanently cease operations based on a demonstration consistent with this paragraph (a)(13) that operation of the affected EGU is necessary for electric grid reliability.

(i) The State plan must require that the reliability assurance mechanism would only be appliable to the following EGUs which, for the purpose of this paragraph (a)(13), are collectively referred to as ''eligible EGUs'':

(A) Coal-fired steam generating units that are exempt from these emission guidelines pursuant to § 60.5850b(k),

(B) Affected EGUs in the medium-term coal-fired steam-generating subcategory that have enforceable commitments to permanently cease operation before January 1, 2039, in the State plan, and

(C) Affected EGUs that have enforceable dates to permanently cease operation included in the State plan pursuant to § 60.24a(g).

(ii)The date from which an extension would run is the date included in the State plan by which an eligible EGU has committed to permanently cease operation.

(iii) The State plan must provide that an extension is only available to owners or operators of affected EGUs that have satisfied all applicable increments of progress and reporting obligations and milestones in paragraphs (a)(5) and (6) of this section. This includes requiring that the owner or operator of an affected EGU has posted all information relevant to such increments of progress and reporting obligations and milestones on the Carbon Pollution Standards for EGUs website, described in § 60.5740b(a)(10).

(iv) The State plan must provide that any applicable standard of performance for an affected EGU must remain in place during the duration of an extension provided under this mechanism.

(v) The State plan may provide for requests for an extension of up to 12 months without a State plan revision.

(A) For an extension of 6 months or less, the owner or operator of the eligible EGU requesting the extension must submit the information in paragraph (a)(13)(vi) to the applicable EPA Regional Administrator to review and approve or disapprove the extension request.

(B) For an extension of more than 6 months and up to 12 months, the owner or operator of the eligible EGU requesting the extension must submit the information in paragraph (a)(13)(vii) to the Federal Energy Regulatory Commission (through a process and at an office of the Federal Energy Regulatory Commission's designation) and to the applicable EPA Regional Administrator to review and approve or disapprove the extension request.

(vi) The State plan must require that to apply for an extension for 6 months or less, described in paragraph (a)(13)(v)(A) of this section, the owner or operator of an eligible EGU must submit a complete written application that includes the information listed in paragraphs (a)(13)(vi)(A) through (D) of this section no less than 30 days prior to the cease operation date, but no earlier than 12 months prior to the cease operation date.

(A) An analysis of the reliability risk that clearly demonstrates that the eligible EGU is critical to maintaining electric reliability. The analysis must include a projection of the length of time that the EGU is expected to be reliability-critical and the length of the requested extension must be no longer than this period or 6 months, whichever is shorter. In order to show an approvable reliability need, the analysis must clearly demonstrate that an eligible EGU ceasing operation by the date listed in the State plan would cause one or more of the conditions listed in paragraphs (a)(13)(vi)(A)(*1*) or (*2*) of this section. An eligible EGU that has received a Reliability Must Run designation, or equivalent from a Reliability Coordinator or Balancing Authority, would fulfill those conditions.

(1) Result in noncompliance with at least one of the mandatory reliability standards approved by FERC; or

(2) Would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, this requires a clear demonstration that the eligible EGU would be needed to maintain the targeted level of resource adequacy.

(B) Certification from the relevant reliability planning authority that the claims of reliability risk are accurate and that the identified reliability problem both exists and requires the specific relief requested. This certification must be accompanied by a written analysis by the relevant planning authority consistent with paragraph (a)(13)(vi)(A) of this section, confirming the asserted reliability risk if the eligible EGU was not in operation. The information from the relevant reliability planning authority must also include any related system-wide or regional analysis and a substantiation of the length of time that the eligible EGU is expected to be reliability critical.

(C) Copies of any written comments from third parties regarding the extension.

(D) Demonstration from the owner or operator of the eligible EGU, grid operator, and other relevant entities of a plan, including appropriate actions to bring on new capacity or transmission, to resolve the underlying reliability issue is leading to the need to employ this reliability assurance mechanism, including the steps and timeframes for implementing measures to rectify the underlying reliability issue.

(E) Any other information requested by the applicable EPA Regional Administrator or the Federal Energy Regulatory Commission.

(vii) The State plan must require that to apply for an extension longer than 6 months but up to 12 months, described in paragraph (a)(13)(v)(B) of this section, the owner or operator of an eligible EGU must submit a complete written application that includes the information listed in (a)(13)(vi)(A) through (E) of this section, except that the period of time under (a)(13)(vi)(A) would be 12 months. For requests for extensions longer than 6 months, this application must be submitted to the EPA Regional Administrator no less than 45 days prior to the date for ceasing operation listed in the State plan, but no earlier than 12 months prior to that date.

(viii) The State plan must provide that extensions will only be granted for the period of time that is substantiated by the reliability need and the submitted analysis and documentation, and shall not exceed 12 months in total.

(ix) The State plan must provide that the reliability assurance mechanism shall not be used more than once to

extend an eligible EGU's planned cease operation date.

(x) The EPA Regional Administrator may reject the application if the submission is incomplete with respect to the requirements listed in paragraphs (a)(13)(vi)(A) through (E) of this section or if the submission does not adequately support the asserted reliability risk or the period of time for which the eligible EGU is anticipated to be reliability critical.

(b) [Reserved]

§ 60.5775b What standards of performance must I include in my State plan?

(a) For each affected EGU, your State plan must include the standard of performance that applies for the affected EGU. A standard of performance for an affected EGU may take the following forms:

(1) A rate-based standard of performance for an individual affected EGU that does not exceed the level calculated through the use of the methods described in § 60.5775b(c) and (d).

(2) A standard of performance in an alternate form, which may apply for affected EGUs in the long-term coal-fired steam generating unit subcategory or the medium-term coal-fired steam generating unit subcategory, as provided for in § 60.5775b(e).

(b) Standard(s) of performance for affected EGUs included under your State plan must be demonstrated to be quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected EGU. The State plan submittal must include the methods by which each standard of performance meets each of the following requirements:

(1) An affected EGU's standard of performance is quantifiable if it can be reliably measured in a manner that can be replicated.

(2) An affected EGU's standard of performance is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the State and the Administrator to independently evaluate, measure, and verify compliance with the standard of performance.

(3) An affected EGU's standard of performance is non-duplicative with respect to a State plan if it is not already incorporated as an standard of performance in the State plan.

(4) An affected EGU's standard of performance is permanent if the standard of performance must be met continuously unless it is replaced by another standard of performance in an approved State plan revision.

(5) An affected EGU's standard of performance is enforceable if:

(i) A technically accurate limitation or requirement, and the time period for the limitation or requirement, are specified;

(ii) Compliance requirements are clearly defined;

(iii) The affected EGUs are responsible for compliance and liable for violations identified;

(iv) Each compliance activity or measure is enforceable as a practical matter, as defined by 40 CFR 49.167; and

(v) The Administrator, the State, and third parties maintain the ability to enforce against violations (including if an affected EGU does not meet its standard of performance based on its emissions) and secure appropriate corrective actions: in the case of the Administrator, pursuant to CAA sections 113(a)–(h); in the case of a State, pursuant to its State plan, State law or CAA section 304, as applicable; and in the case of third parties, pursuant to CAA section 304.

(c) Methodology for establishing presumptively approvable standards of performance, for affected EGUs in each subcategory.

(1) Long-term coal-fired steam generating units

(i) BSER is CCS with 90 percent capture of CO_2.

(ii) Degree of emission limitation is 88.4 percent reduction in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an emission rate limit defined by an 88.4 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.

(2) Medium-term coal-fired steam generating units

(i) BSER is natural gas co-firing at 40 percent of the heat input to the unit.

(ii) Degree of emission limitation is a 16 percent reduction in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an emission rate limit defined by a 16 percent reduction in annual emission rate (lb CO_2/MWh-gross) from the unit-specific baseline.

(iv) For units in this subcategory that have an amount of co-firing that is reflected in the baseline operation, States must account for such preexisting co-firing in adjusting the degree of emission limitation (*e.g.,* for an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 12 percent to reflect the preexisting level of natural gas co-firing).

(3) Base load oil-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,400 lb CO_2/MWh-gross.

(4) Intermediate load oil-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,600 lb CO_2/MWh-gross.

(5) Low load oil-fired steam generating units.

(i) BSER is uniform fuels.

(ii) Degree of emission limitation is 170 lb CO_2/MMBtu.

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 170 lb CO_2/MMBtu.

(6) Base load natural gas-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,400 lb CO_2/MWh-gross.

(7) Intermediate load natural gas-fired steam generating units.

(i) BSER is routine methods of operation and maintenance.

(ii) Degree of emission limitation is a 0 percent increase in emission rate (lb CO_2/MWh-gross).

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 1,600 lb CO_2/MWh-gross.

(8) Low load natural gas-fired steam generating.

(i) BSER is uniform fuels.

(ii) Degree of emission limitation is 130 lb CO_2/MMBtu.

(iii) Presumptively approvable standard of performance is an annual emission rate limit of 130 lb CO_2/MMBtu.

(d) Methodology for establishing the unit-specific baseline of emission performance.

(1) A State shall use the CO_2 mass emissions and corresponding electricity

generation or, for affected EGUs in the low load oil- or natural gas-fired subcategory, heat input data for a given affected EGU from the most representative continuous 8-quarter period from 40 CFR part 75 reporting within the 5-year period immediately prior to May 9, 2024.

(2) For the continuous 8 quarters of data, a State shall divide the total CO_2 emissions (in the form of pounds) over that continuous time period by either the total gross electricity generation (in the form of MWh) or, for affected EGUs in the low load oil- or natural gas-fired subcategory, total heat input (in the form of MMBtu) over that same time period to calculate baseline CO_2 emission performance in lb CO_2 per MWh or lb CO_2 per MMBtu.

(e) Your State plan may include a standard of performance in an alternate form that differs from the presumptively approvable standard of performance specified in § 60.5775b(a)(1), as follows:

(1) An aggregate rate-based standard of performance (lb CO_2/MWh-gross) that applies for a group of affected EGUs that share the same owner or operator, as calculated on a gross generation weighted average basis, provided the standard of performance meets the requirements of paragraph (f) of this section.

(2) A mass-based standard of performance in the form of an annual limit on allowable mass CO_2 emissions for an individual affected EGU, provided the standard of performance meets the requirements of paragraph (g) of this section.

(3) A rate-based standard of performance (lb CO_2/MWh-gross) implemented through a rate-based emission trading program, such that an affected EGU must meet the specified lb CO_2/MWh-gross rate that applies for the affected EGU, and where an affected EGU may surrender compliance instruments denoted in 1 short ton of CO_2 to adjust its reported lb CO_2/MWh-gross rate for the purpose of demonstrating compliance, provided the standard of performance meets the requirements of paragraph (h) of this section.

(4) A mass-based standard of performance in the form of an annual CO_2 budget implemented through a mass-based CO_2 emission trading program, where an affected EGU must surrender CO_2 allowances in an amount equal to its reported mass CO_2 emissions, provided the standard of performance meets the requirements of paragraph (i) of this section.

(f) Where your State plan includes a standard of performance in the form of an aggregate rate-based standard of performance (lb CO_2/MWh-gross) that applies for a group of affected EGUs that share the same owner or operator, as calculated on a gross generation weighted average basis, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section, to each of the affected EGUs that form the group.

(2) Documentation of any assumptions underlying the calculation of the aggregate rate-based standard of performance (lb CO_2/MWh-gross).

(3) The process for calculating the aggregate gross generation weighted average emission rate (lb CO_2/MWh-gross) at the end of each compliance period, based on the reported emissions (lb CO_2) and utilization (MWh-gross) of each of the affected EGUs that form the group.

(4) Measures to implement and enforce the annual aggregate rate-based standard of performance, including the basis for determining owner or operator compliance with the aggregate standard of performance and provisions to address any changes to owners or operators in the course of implementation.

(5) A demonstration of how the application of the aggregate rate-based standard of performance will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(g) Where your State plan includes a standard of performance in the form of an annual limit on allowable mass CO_2 emissions for an individual affected EGU, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply to the affected EGU under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) The utilization level used to calculate the mass CO_2 limit, by multiplying the assumed utilization level (MWh-gross) by the presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross), including the underlying data used for the calculation and documentation of any assumptions underlying this calculation.

(3) Measures to implement and enforce the annual limit on mass CO_2 emissions, including provisions that address assurance of achievement of equivalent emission performance.

(4) A demonstration of how the application of the mass CO_2 limit for the affected EGU will achieve equivalent or better emission reduction as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(5) The backstop rate-based emission rate requirement (lb CO_2/MWh-gross) that will also be applied to the affected EGU on an annual basis.

(6) For affected EGUs in the long-term coal-fired steam generating unit subcategory, in lieu of paragraphs (g)(2), (4), and (5) of this section, you may include a presumptively approvable mass CO_2 limit based on the product of the rate-based standard of performance (lb CO_2/MWh-gross) under paragraph (a)(1) of this section multiplied by a level of utilization (MWh-gross) corresponding to an annual capacity factor of 80 percent for the individual affected EGU with a backstop rate-based emission rate requirement equivalent to a reduction in baseline emission performance of 80 percent on an annual calendar-year basis.

(h) Where your State plan includes a standard of performance in the form of a rate-based standard of performance (lb CO_2/MWh-gross) implemented through a rate-based emission trading program, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that applies to each of the affected EGUs participating in the rate-based emission trading program under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) Measures to implement and enforce the rate-based emission trading program, including the basis for awarding compliance instruments (denoted in 1 ton of CO_2) to an affected EGU that performs better on an annual basis than its rate-based standard of performance, and the process for demonstration of compliance that includes the surrender of such compliance instruments by an affected EGU that exceeds its rate-based standard of performance.

(3) A demonstration of how the use of the rate-based emission trading program will achieve equivalent or better emission reduction as would be achieved through the application of a

rate-based standard of performance (lb CO_2/MWh-gross) that would apply pursuant to paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(i) Where your State plan includes a mass-based standard of performance implemented through a mass-based CO_2 emission trading program, where an affected EGU must surrender CO_2 allowances in an amount equal to its reported mass CO_2 emissions, your State plan must include:

(1) The presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross) that would apply to each affected EGU participating in the trading program under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(2) The calculation of the mass CO_2 budget contribution for each participating affected EGU, determined by multiplying the assumed utilization level (MWh-gross) of the affected EGU by its presumptively approvable rate-based standard of performance (lb CO_2/MWh-gross), including the underlying data used for the calculation and documentation of any assumptions underlying this calculation.

(3) Measures to implement and enforce the annual budget of the mass-based CO_2 emission trading program, including provisions that address assurance of achievement of equivalent emission performance.

(4) A demonstration of how the application of the CO_2 emission budget for the group of participating affected EGUs will achieve equivalent or better emission performance as would be achieved through the application of a rate-based standard of performance (lb CO_2/MWh-gross) that would apply to each participating affected EGU under paragraph (a)(1) of this section, and as determined in accordance with paragraphs (c) and (d) of this section.

(5) The backstop rate-based emission rate requirement (lb CO_2/MWh-gross) that will also be applied to each participating affected EGU on an annual basis.

(j) In order to use the provisions of § 60.24a(e) through (h) to apply a less stringent standard of performance or longer compliance schedule to an affected EGU based on consideration of electric grid reliability, including resource adequacy, under these emission guidelines, a State must provide the following with its State plan submission:

(1) An analysis of the reliability risk clearly demonstrating that the particular affected EGU is critical to maintaining electric reliability such that requiring it to comply with the applicable requirements under paragraph (c) of this section or § 60.5780b would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission or would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region; specifically, a clear demonstration is required that the particular affected EGU would be needed to maintain the targeted level of resource adequacy. The analysis must also include a projection of the period of time for which the particular affected EGU is expected to be reliability critical and substantiate the basis for applying a less stringent standard of performance or longer compliance schedule consistent with 40 CFR 60.24a(e).

(2) An analysis by the relevant reliability planning authority that corroborates the asserted reliability risk identified in the analysis under paragraph (j)(1) of this section and confirms that requiring the particular affected EGU to comply with its applicable requirements under paragraph (c) of this section or § 60.5780b would trigger non-compliance with at least one of the mandatory reliability standards approved by the Federal Energy Regulatory Commission or would cause the loss of load expectation to increase beyond the level targeted by regional system planners as part of their established procedures for that particular region, and also confirms the period of time for which the EGU is projected to be reliability critical.

(3) A certification from the relevant reliability planning authority that the claims of reliability risk are accurate and that the identified reliability problem both exists and requires the specific relief requested.

§ 60.5780b What compliance dates and compliance periods must I include in my State plan?

(a) The State plan must include the following compliance dates:

(1) For affected EGUs in the long-term coal-fired subcategory, the State plan must require compliance with the applicable standards of performance starting no later than January 1, 2032, unless the State has applied a later compliance date pursuant to § 60.24a(e) through (h).

(2) For affected EGUs in the medium-term coal-fired subcategory, the base load oil-fired subcategory, the intermediate load oil-fired steam generating subcategory, the low load oil-fired subcategory, the base load natural gas-fired subcategory, the intermediate load natural gas-fired subcategory, and the low load natural gas-fired subcategory, the State plan must require compliance with the applicable standards of performance starting no later than January 1, 2030, unless State has applied a later compliance date pursuant to § 60.24a(e) through (h).

(b) The State plan must require affected EGUs to achieve compliance with their applicable standards of performance for each compliance period as defined in § 60.5880b.

§ 60.5785b What are the timing requirements for submitting my State plan?

(a) You must submit a State plan or a negative declaration letter with the information required under § 60.5740b by May 11, 2026.

(b) You must submit all information required under paragraph (a) of this section according to the electronic reporting requirements in § 60.5875b.

§ 60.5790b What is the procedure for revising my State plan?

EPA-approved State plans can be revised only with approval by the Administrator. The Administrator will approve a State plan revision if it is satisfactory with respect to the applicable requirements of this subpart and all applicable requirements of subpart Ba of this part. If one (or more) of State plan elements in § 60.5740b require revision, the State must submit a State plan revision pursuant to § 60.28a.

§ 60.5795b Commitment to review emission guidelines for coal-fired affected EGUs

EPA will review and, if appropriate, revise these emission guidelines as they apply to coal-fired steam generating affected EGUs by January 1, 2041. Notwithstanding this commitment, EPA need not review these emission guidelines if the Administrator determines that such review is not appropriate in light of readily available information on their continued appropriateness.

Applicability of State Plans to Affected EGUs

§ 60.5840b Does this subpart directly affect EGU owners or operators in my State?

(a) This subpart does not directly affect EGU owners or operators in your State, except as provided in § 60.5710b(b). However, affected EGU owners or operators must comply with the State plan that a State develops to

implement the emission guidelines contained in this subpart.

(b) If a State does not submit a State plan to implement and enforce the standards of performance contained in this subpart by May 11, 2026, or the EPA disapproves State plan, the EPA will implement and enforce a Federal plan, as provided in § 60.5720b, applicable to each affected EGU within the State.

§ 60.5845b What affected EGUs must I address in my State plan?

(a) The EGUs that must be addressed by your State plan are:

(1) Any affected EGUs that were in operation or had commenced construction on or before January 8, 2014;

(2) Coal-fired steam generating units that commenced a modification on or before May 23, 2023.

(b) An affected EGU is a steam generating unit that meets the relevant applicability conditions specified in paragraphs (b)(1) through (2) of this section, as applicable, except as provided in § 60.5850b.

(1) Serves a generator capable of selling greater than 25 MW to a utility power distribution system; and

(2) Has a base load rating (*i.e.,* design heat input capacity) greater than 260 GJ/hr (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel).

§ 60.5850b What EGUs are excluded from being affected EGUs?

EGUs that are excluded from being affected EGUs are:

(a) New or reconstructed steam generating units that are subject to subpart TTTT of this part as a result of commencing construction after the subpart TTTT applicability date;

(b) Modified natural gas- or oil-fired steam generating units that are subject to subpart TTTT of this part as a result of commencing modification after the subpart TTTT applicability date;

(c) Modified coal-fired steam generating units that are subject to subpart TTTTa of this part as a result of commencing modification after the subpart TTTTa applicability date;

(d) EGUs subject to a federally enforceable permit limiting net-electric sales to one-third or less of their potential electric output or 219,000 MWh or less on an annual basis and annual net-electric sales have never exceeded one-third or less of their potential electric output or 219,000 MWh;

(e) Non-fossil fuel units (*i.e.,* units that are capable of deriving at least 50 percent of heat input from non-fossil fuel at the base load rating) that are subject to a federally enforceable permit limiting fossil fuel use to 10 percent or less of the annual capacity factor;

(f) CHP units that are subject to a federally enforceable permit limiting annual net-electric sales to no more than either 219,000 MWh or the product of the design efficiency and the potential electric output, whichever is greater;

(g) Units that serve a generator along with other EGUs, where the effective generation capacity (determined based on a prorated output of the base load rating of each EGU) is 25 MW or less;

(h) Municipal waste combustor units subject to 40 CFR part 60, subpart Eb;

(i) Commercial or industrial solid waste incineration units that are subject to 40 CFR part 60, subpart CCCC; or

(j) EGUs that derive greater than 50 percent of the heat input from an industrial process that does not produce any electrical or mechanical output or useful thermal output that is used outside the affected EGU.

(k) Existing coal-fired steam generating units that have demonstrated that they plan to permanently cease operations before January 1, 2032, pursuant to § 60.5740b(a)(9)(ii).

Recordkeeping and Reporting Requirements

§ 60.5860b What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my State plan for affected EGUs?

(a) Your State plan must include monitoring for affected EGUs that is no less stringent than what is described in (a)(1) through (9) of this section.

(1) The owner or operator of an affected EGU (or group of affected EGUs that share a monitored common stack) that is required to meet standards of performance must prepare a monitoring plan in accordance with the applicable provisions in 40 CFR 75.53(g) and (h), unless such a plan is already in place under another program that requires CO_2 mass emissions to be monitored and reported according to 40 CFR part 75.

(2) For rate-based standards of performance, only ''valid operating hours,'', *i.e.,* full or partial unit (or stack) operating hours for which:

(i) ''Valid data'' (as defined in § 60.5880b) are obtained for all of the parameters used to determine the hourly CO_2 mass emissions (lbs). For the purposes of this subpart, substitute data recorded under part 75 of this chapter are not considered to be valid data; data obtained from flow monitoring bias adjustments are not considered to be valid data; and data provided or not provided from monitoring instruments that have not met the required frequency for relative accuracy audit testing are not considered to be valid data and

(ii) The corresponding hourly gross energy output value is also valid data (Note: For operating hours with no useful output, zero is considered to be a valid value).

(3) For rate-based standards of performance, the owner or operator of an affected EGU must measure and report the hourly CO_2 mass emissions (lbs) from each affected unit using the procedures in paragraphs (a)(3)(i) through (vi) of this section, except as otherwise provided in paragraph (a)(4) of this section.

(i) The owner or operator of an affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to 40 CFR 75.10(a)(3)(i). As an alternative to direct measurement of CO_2 concentration, provided that the affected EGU does not use carbon separation (*e.g.,* carbon capture and storage (CCS)), the owner or operator of an affected EGU may use data from a certified oxygen (O_2) monitor to calculate hourly average CO_2 concentrations, in accordance with 40 CFR 75.10(a)(3)(iii). However, when an O_2 monitor is used this way, it only quantifies the combustion CO_2; therefore, if the EGU is equipped with emission controls that produce non-combustion CO_2 (*e.g.,* from sorbent injection), this additional CO_2 must be accounted for, in accordance with section 3 of appendix G to part 75 of this chapter. If CO_2 concentration is measured on a dry basis, the owner or operator of the affected EGU must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to 40 CFR 75.11(b). Alternatively, the owner or operator of an affected EGU may either use an appropriate fuel-specific default moisture value from 40 CFR 75.11(b) or submit a petition to the Administrator under 40 CFR 75.66 for a site-specific default moisture value.

(ii) For each ''valid operating hour'' (as defined in paragraph (a)(2) of this section), calculate the hourly CO_2 mass emission rate (tons/hr), either from Equation F–11 in appendix F to 40 CFR part 75 (if CO_2 concentration is measured on a wet basis), or by following the procedure in section 4.2 of appendix F to 40 CFR part 75 (if CO_2

concentration is measured on a dry basis).

(iii) Next, multiply each hourly CO_2 mass emission rate by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6), if required by a State plan. The owner or operator must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values from paragraph (a)(3)(ii) of this section.

(vi) For each continuous monitoring system used to determine the CO_2 mass emissions from an affected EGU, the monitoring system must meet the applicable certification and quality assurance procedures in 40 CFR 75.20 and appendices A and B to 40 CFR part.

(4) The owner or operator of an affected EGU that exclusively combusts liquid fuel and/or gaseous fuel may, as an alternative to complying with paragraph (a)(3) of this section, determine the hourly CO_2 mass emissions according to paragraphs (a)(4)(i) through (a)(4)(vi) of this section.

(i) Implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly EGU heat input rates (MMBtu/hr), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted. The fuel flow meter(s) used to measure the hourly fuel flow rates must meet the applicable certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 of appendix D to 40 CFR part 75 (except for qualifying commercial billing meters). The fuel GCV must be determined in accordance with section 2.2 or 2.3 of appendix D to 40 CFR part 75, as applicable.

(ii) For each measured hourly heat input rate, use Equation G–4 in appendix G to 40 CFR part 75 to calculate the hourly CO_2 mass emission rate (tons/hr).

(iii) For each ''valid operating hour'' (as defined in paragraph (a)(2) of this section), multiply the hourly tons/hr CO_2 mass emission rate from paragraph (a)(4)(ii) of this section by the EGU or stack operating time in hours (as defined in 40 CFR 72.2), to convert it to tons of CO_2. Then, multiply the result by 2,000 lbs/ton to convert it to lbs.

(iv) The hourly CO_2 tons/hr values and EGU (or stack) operating times used to calculate CO_2 mass emissions are required to be recorded under 40 CFR 75.57(e) and must be reported electronically under 40 CFR 75.64(a)(6), if required by a State plan. You must use these data, or equivalent data, to calculate the hourly CO_2 mass emissions.

(v) Sum all of the hourly CO_2 mass emissions values (lb) from paragraph (a)(4)(iii) of this section.

(vi) The owner or operator of an affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to 40 CFR part 75 and may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(5) For rate-based standards, the owner or operator of an affected EGU (or group of affected units that share a monitored common stack) must install, calibrate, maintain, and operate equipment to continuously measure and record on an hourly basis gross electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI No. C12.20–2010 (incorporated by reference, see § 60.17). Further, the owner or operator of an affected EGU that is a combined heat and power facility must install, calibrate, maintain, and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with gross electric output to determine gross energy output. The owner or operator must use the following procedures to calculate gross energy output, as appropriate for the type of affected EGU(s).

(i) Determine $P_{gross/net}$ the hourly gross or net energy output in MWh. For rate-based standards, perform this calculation only for valid operating hours (as defined in paragraph (a)(2) of this section). For mass-based standards, perform this calculation for all unit (or stack) operating hours, *i.e.,* full or partial hours in which any fuel is combusted.

(ii) If there is no net electrical output, but there is mechanical or useful thermal output, either for a particular valid operating hour (for rate-based applications), or for a particular operating hour (for mass-based applications), the owner or operator of the affected EGU must still determine the net energy output for that hour.

(iii) For rate-based applications, if there is no (*i.e.,* zero) gross electrical, mechanical, or useful thermal output for a particular valid operating hour, that hour must be used in the compliance determination. For hours or partial hours where the gross electric output is equal to or less than the auxiliary loads, net electric output shall be counted as zero for this calculation.

(iv) Calculate $P_{gross/net}$ for your affected EGU (or group of affected EGUs that share a monitored common stack) using the following equation. All terms in the equation must be expressed in units of MWh. To convert each hourly gross or net energy output value reported under 40 CFR part 75 to MWh, multiply by the corresponding EGU or stack operating time.

Equation 1 to Paragraph (a)(5)(iv)

$$P_{gross/net} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{A}}{TDF} + [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

$P_{GROSS/NET}$ = Gross or net energy output of your affected EGU for each valid operating hour (as defined in 60.5860b(a)(2)) in MWh.

$(PE)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(PE)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(PE)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected egu's integrated equipment that provides electricity or mechanical energy to the affected EGU or auxiliary equipment in MWh.

$(PE)_{A}$ = Electric energy used for any auxiliary loads in MWh.

$(PT)_{PS}$ = Useful thermal output of steam (measured relative to SATP conditions, as applicable) that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected EGU. This is calculated using the equation specified in paragraph (a)(5)(V) of this section in MWh.

$(PT)_{HR}$ = Non-steam useful thermal output (measured relative to SATP conditions, as applicable) from heat recovery that is used for applications other than steam generation or performance enhancement of the affected EGU in MWh.

$(PT)_{IE}$ = Useful thermal output (relative to SATP conditions, as applicable) from any integrated equipment is used for applications that do not generate additional steam, electricity, produce mechanical energy output, or enhance the performance of the affected EGU in MWh.

TDF = Electric transmission and distribution factor of 0.95 for a combined heat and power affected egu where at least on an annual basis 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and 20.0 percent of the total gross or net energy output consist of useful thermal output on a 12-operating month rolling average basis, or 1.0 for all other affected EGUs.

(v) If applicable to your affected EGU (for example, for combined heat and power), you must calculate $(Pt)_{PS}$ using the following equation:

Equation 2 to Paragraph (a)(5)(v)

$$(Pt)_{PS} = \frac{Q_m \times H}{CF}$$

Where:

Q_M = Measured steam flow in kilograms (KG) (or pounds (LBS)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure (relative to SATP conditions or the energy in the condensate return line, as applicable) in joules per kilogram (J/KG) (or BTU/LB).

CF = Conversion factor of 3.6×10^9 J/MWH or 3.413×10^6 BTU/MWh.

(vi) For rate-based standards, sum all of the values of $P_{gross/net}$ for the valid operating hours (as defined in paragraph (a)(2) of this section). Then, divide the total CO_2 mass emissions for the valid operating hours from paragraph (a)(3)(v) or (a)(4)(v) of this section, as applicable, by the sum of the $P_{gross/net}$ values for the valid operating hours to determine the CO_2 emissions rate (lb/gross or net MWh).

(6) In accordance with § 60.13(g), if two or more affected EGUs implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section share a common exhaust gas stack and are subject to the same emissions standard, the owner or operator may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an owner or operator of an affected EGU chooses this option, the hourly gross or net electric output for the common stack must be the sum of the hourly gross or net electric output of the individual affected EGUs and the operating time must be expressed as ''stack operating hours'' (as defined in 40 CFR 72.2).

(7) In accordance with § 60.13(g), if the exhaust gases from an affected EGU implementing the continuous emissions monitoring provisions in paragraph (a)(3) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in 40 CFR 72.2) at each stack or duct must be monitored separately. In this case, the owner or operator of an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the gross or net energy output for the affected EGU.

(8) Consistent with § 60.5775b, if two or more affected EGUs serve a common electric generator, you must apportion the combined hourly gross or net energy output to the individual affected EGUs according to the fraction of the total steam load contributed by each EGU. Alternatively, if the EGUs are identical, you may apportion the combined hourly gross or net electrical load to the individual EGUs according to the fraction of the total heat input contributed by each EGU.

(9) The owner or operator of an affected EGU must measure and report monthly fuel usage for each affected source subject to standards of performance with the information in paragraphs (a)(9)(i) through (iii) of this section:

(i) The calendar month during which the fuel was used;

(ii) Each type of fuel used during the calendar month of the compliance period; and

(iii) Quantity of each type of fuel combusted in each calendar month in the compliance period with units of measure.

(b) Your State plan must require the owner or operator of each affected EGU covered by your State plan to maintain the records, for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) The owner or operator of an affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, whichever is latest, according to § 60.7. The owner or operator of an affected EGU may maintain the records off site and electronically for the remaining year(s).

(2) The owner or operator of an affected EGU must keep all of the following records, in a form suitable and readily available for expeditious review:

(i) All documents, data files, and calculations and methods used to demonstrate compliance with an affected EGU's standard of performance under § 60.5775b.

(ii) Copies of all reports submitted to the State under paragraph (b) of this section.

(iii) Data that are required to be recorded by 40 CFR part 75 subpart F.

(c) Your State plan must require the owner or operator of an affected EGU covered by your State plan to include in a report submitted to you the information in paragraphs (c)(1) through (3) of this section.

(1) Owners or operators of an affected EGU must include in the report all hourly CO_2 emissions, for each affected EGU (or group of affected EGUs that share a monitored common stack).

(2) For rate-based standards, each report must include:

(i) The hourly CO_2 mass emission rate values (tons/hr) and unit (or stack) operating times, (as monitored and reported according to part 75 of this chapter), for each valid operating hour;

(ii) The gross or net electric output and the gross or net energy output ($P_{gross/net}$) values for each valid operating hour;

(iii) The calculated CO_2 mass emissions (lb) for each valid operating hour;

(iv) The sum of the hourly gross or net energy output values and the sum of the

hourly CO_2 mass emissions values, for all of the valid operating hours; and

(v) The calculated CO_2 mass emission rate (lbs/gross or net MWh).

(3) For each affected EGU the report must also include the applicable standard of performance and demonstration that it met the standard of performance. An owner or operator must also include in the report the affected EGU's calculated emission performance as a CO_2 emission rate in units of the standard of performance.

(d) The owner or operator of an affected EGU must follow any additional requirements for monitoring, recordkeeping and reporting in a State plan that are required under § 60.5740b if applicable.

(e) If an affected EGU captures CO_2 to meet the applicable standard of performance, the owner or operator must report in accordance with the requirements of 40 CFR part 98 subpart PP and either:

(1) Report in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs on-site;

(2) Transfer the captured CO_2 to a facility that reports in accordance with the requirements of 40 CFR part 98, subpart RR, or subpart VV, if injection occurs off-site; or

(3) Transfer the captured CO_2 to a facility that has received an innovative technology waiver from the EPA pursuant to paragraph (f) of this section.

(f) Any person may request the Administrator to issue a waiver of the requirement that captured CO_2 from an affected EGU be transferred to a facility reporting under 40 CFR part 98, subpart RR, or subpart VV. To receive a waiver, the applicant must demonstrate to the Administrator that its technology will store captured CO_2 as effectively as geologic sequestration, and that the proposed technology will not cause or contribute to an unreasonable risk to public health, welfare, or safety. In making this determination, the Administrator shall consider (among other factors) operating history of the technology, whether the technology will increase emissions or other releases of any pollutant other than CO_2, and permanence of the CO_2 storage. The Administrator may test the system or require the applicant to perform any tests considered by the Administrator to be necessary to show the technology's effectiveness, safety, and ability to store captured CO_2 without release. The Administrator may grant conditional approval of a technology, with the approval conditioned on monitoring and reporting of operations. The Administrator may also withdraw approval of the waiver on evidence of releases of CO_2 or other pollutants. The Administrator will provide notice to the public of any application under this provision and provide public notice of any proposed action on a petition before the Administrator takes final action.

§ 60.5865b What are my recordkeeping requirements?

(a) You must keep records of all information relied upon in support of any demonstration of State plan components, State plan requirements, supporting documentation, and the status of meeting the State plan requirements defined in the State plan.

(b) You must keep records of all data submitted by the owner or operator of each affected EGU that are used to determine compliance with each affected EGU emissions standard or requirements in an approved State plan, consistent with the affected EGU requirements listed in § 60.5860b.

(c) If your State has a requirement for all hourly CO_2 emissions and gross generation or heat input information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted by the owners or operators of affected EGUs to the EPA electronically pursuant to requirements in 40 CFR part 75 meets the recordkeeping requirement of this section and you are not required to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) You must keep records for a minimum of 10 years from the date the record is used to determine compliance with an emissions standard or State plan requirement. Each record must be in a form suitable and readily available for expeditious review.

(e) If your State plan includes provisions for the compliance date extension, described in § 60.5740b(a)(11), you must keep records of the information required in § 60.5740b(a)(11)(i) from affected EGUs that use the compliance date extension.

(f) If your State plan includes provisions for the short-term reliability mechanism, as described in § 60.5740b(a)(12), you must keep records of the information required in § 60.5740b(a)(12)(iii) from affected EGUs that use the short-term reliability mechanism.

(g) If your State plan includes provisions for the reliability assurance mechanism, described in § 60.5740b(a)(13), you must keep records of the information required in § 60.5740b(a)(13)(vi) from affected EGUs that use the reliability assurance mechanism.

§ 60.5870b What are my reporting and notification requirements?

(a) In lieu of the annual report required under § 60.25(e) and (f), you must report the information in paragraph (b) of this section.

(b) You must submit an annual report to the EPA that must include the information in paragraphs (b)(1) through (10) of this section. For each calendar year reporting period the report must be submitted by March 1 of the following year.

(1) The report must include the emissions performance achieved by each affected EGU during the reporting period and identification of whether each affected EGU is in compliance with its standard of performance during the compliance period, as specified in the State plan.

(2) The report must include, for each affected EGU, a comparison of the CO_2 standard of performance in the State plan versus the actual CO_2 emission performance achieved.

(3) The report must include, for each affected EGU, the sum of the CO_2 emissions, the sum of the gross energy output, and the sum of the heat input for each fuel type.

(4) Enforcement actions initiated against affected EGUs during the reporting period, under any standard of performance or compliance schedule of the State plan.

(5) Identification of the achievement of any increment of progress required by the applicable State plan during the reporting period.

(6) Identification of designated facilities that have ceased operation during the reporting period.

(7) Submission of emission inventory data as described in paragraph (a) of this section for designated facilities that were not in operation at the time of State plan development but began operation during the reporting period.

(8) Submission of additional data as necessary to update the information submitted under paragraph (a) of this section or in previous progress reports.

(9) Submission of copies of technical reports on all performance testing on designated facilities conducted under paragraph (b)(2) of this section, complete with concurrently recorded process data.

(10) The report must include all other required information, as specified in your State plan according to § 60.5740b.

(c) If you include provisions for the compliance date extension, described in § 60.5740b(a)(11), in your State plan, you must report to the EPA the information listed in § 60.5740b(a)(11)(i).

(d) If you include provisions for the short-term reliability mechanism, described in § 60.5740b(a)(12), in your State plan, you must report to the EPA the following information for each event, listed in § 60.5740b(a)(12)(iii).

(e) If you include provisions for the reliability assurance mechanism, described in § 60.5740b(a)(13) in your State plan, you must report to the EPA the information listed in § 60.5740b(a)(13)(vi).

§ 60.5875b How do I submit information required by these emission guidelines to the EPA?

(a) You must submit to the EPA the information required by these emission guidelines following the procedures in paragraphs (b) through (e) of this section.

(b) All State plan submittals, supporting materials that are part of a State plan submittal, any State plan revisions, and all State reports required to be submitted to the EPA by the State plan must be reported through the EPA's State Plan Electronic Collection System (SPeCS). SPeCS is a web accessible electronic system accessed at the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx/*). States that claim that a State plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539–01, 4930 Old Page Rd., Durham, NC 27703.

(c) Only a submittal by the Governor or the Governor's designee by an electronic submission through SPeCS shall be considered an official submittal to the EPA under this subpart. If the Governor wishes to designate another responsible official the authority to submit a State plan, the EPA must be notified via letter from the Governor prior to the May 11, 2026, deadline for State plan submittal so that the official will have the ability to submit the initial or final State plan submittal in the SPeCS. If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a State may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the State plan preparers who will need access to SPeCS. A State may also submit the names of the State plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the State plan administrative process. Required contact information for the designee and preparers includes the person's title, organization, and email address.

(d) The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version all State plan components designated as federally enforceable must also be submitted in an editable version. Following initial State plan approval, States must provide the EPA with an editable copy of any submitted revision to existing approved federally enforceable State plan components, including State plan backstop measures. The editable copy of any such submitted State plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable State plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by the EPA.

(e) You must provide the EPA with non-editable and editable copies of any submitted revision to existing approved federally enforceable State plan components. The editable copy of any such submitted State plan revision must indicate the changes made at the State level, if any, to the existing approved federally enforceable State plan components, using a mechanism such as redline/strikethrough. These changes are not part of the State plan until formal approval by the EPA.

§ 60.5876b What are the recordkeeping and reporting requirements for EGUs that have committed to permanently cease operations by January 1, 2032?

(a) If you are the owner or operator of an EGU that has committed to permanently cease operations by January 1, 2032, you must maintain records for and submit the reports listed in paragraphs (a)(1) through (3) of this section according to the electronic reporting requirements in paragraph (b) of this section.

(1) Five years before any planned date to permanently cease operations or by the date upon which the State plan is submitted, whichever is later, the owner or operator of the EGU must submit an initial report to the EPA that includes the information in paragraphs (a)(1)(i) and (ii) of this section.

(i) A summary of the process steps required for the EGU to permanently cease operation by the date included in the State plan, including the approximate timing and duration of each step and any notification requirements associated with deactivation of the unit. These process steps may include, *e.g.,* initial notice to the relevant reliability authority of the deactivation date and submittal of an official retirement filing (or equivalent filing) made to the EGU's relevant reliability authority.

(ii) Supporting regulatory documents, which include those listed in paragraphs (a)(1)(ii)(A) through (G) of this section:

(A) Correspondence and official filings with the relevant regional RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority;

(B) Any deactivation-related reliability assessments conducted by the RTO or Independent System Operator;

(C) Any filings pertaining to the affected EGU with the SEC or notices to investors, including but not limited to references in forms 10–K and 10–Q, in which plans for the EGU are mentioned;

(D) Any integrated resource plans and PUC orders approving the EGU's deactivation;

(E) Any reliability analyses developed by the RTO, Independent System Operator, or relevant reliability authority in response to the EGU's deactivation notification;

(F) Any notification from a relevant reliability authority that the EGU may be needed for reliability purposes notwithstanding the EGU's intent to deactivate; and

(G) Any notification to or from an RTO, Independent System Operator, or relevant reliability authority altering the timing of deactivation of the EGU.

(2) For each of the remaining years prior to the date by which an EGU has committed to permanently cease operations, the owner or operator of the EGU must submit an annual status report to the EPA that includes the information listed in paragraphs (a)(2)(i) and (ii) of this section:

(i) Progress on each of the identified process steps identified in the initial report as described in paragraph (a)(1)(i) of this section; and

(ii) Supporting regulatory documents, including correspondence and official filings with the relevant RTO, Independent System Operator, Balancing Authority, PUC, or other applicable authority to demonstrate progress toward all steps described in paragraph (a)(1)(i) of this section.

(3) The owner or operator must submit a final report to the EPA no later than 6 months following its committed closure date. This report must document any actions that the EGU has taken subsequent to ceasing operation to

ensure that such cessation is permanent, including any regulatory filings with applicable authorities or decommissioning plans.

(b) Beginning November 12, 2024, if you are the owner or operator of an EGU that has committed to permanently cease operations by January 1, 2032, you must submit all the information required in paragraph (a) of this section in a Permanent Cessation of Operation report in PDF format following the procedures specified in paragraph (c) of this section.

(c) If you are required to submit notifications or reports following the procedure specified in this paragraph (c), you must submit notifications or reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information in the report or notification, you must submit a complete file in the format specified in this subpart, including information claimed to be CBI, to the EPA following the procedures in paragraphs (c)(1) and (2) of this section. Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this paragraph (c).

(1) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address *oaqpscbi@epa.gov*, and as described above, should include clear CBI markings and be flagged to the attention of the Emission Guidelines for Greenhouse Gas Emissions for Electric Utility Generating Units Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(2) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: U.S. EPA Attn: OAQPS Document Control Officer, Mail Drop: C404–02, 109 T.W. Alexander Drive P.O. Box 12055, RTP, NC 27711. All other files should also be sent to the attention of the Greenhouse Gas Emissions for Electric Utility Generating Units Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(d) Any records required to be maintained by this subpart that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

(e) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (e)(1) through (7) of this section.

(1) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(2) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(3) The outage may be planned or unplanned.

(4) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(5) You must provide to the Administrator a written description identifying:

(i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(6) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(7) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(f) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* you must meet the requirements outlined in paragraphs(f)(1) through (5) of this section.

(1) You may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(2) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(3) You must provide to the Administrator:

(i) A written description of the *force majeure* event;

(ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(iii) A description of measures taken or to be taken to minimize the delay in reporting; and

(iv) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(4) The decision to accept the claim of *force majeure* and allow an extension

to the reporting deadline is solely within the discretion of the Administrator.

(5) In any circumstance, the reporting must occur as soon as possible after the *force majeure* event occurs.

(g) Alternatives to any electronic reporting required by this subpart must be approved by the Administrator.

Definitions

§ 60.5880b What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A, Ba, TTTT, and TTTTa, of this part.

Affected electric generating unit or *Affected EGU* means a steam generating unit that meets the relevant applicability conditions in section § 60.5845b.

Annual capacity factor means the ratio between the actual heat input to an EGU during a calendar year and the potential heat input to the EGU had it been operated for 8,760 hours during a calendar year at the base load rating.

Base load rating means the maximum amount of heat input (fuel) that an EGU can combust on a steady-state basis, as determined by the physical design and characteristics of the EGU at ISO conditions, as defined below. For a stationary combustion turbine or IGCC, *base load rating* includes the heat input from duct burners.

Coal-fired steam generating unit means an electric utility steam generating unit or IGCC unit that meets the definition of ''fossil fuel-fired'' and that burns coal for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029, or that retains the capability to fire coal after December 31, 2029.

Combined cycle unit means a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power unit or *CHP unit,* (also known as ''cogeneration'') means an electric generating unit that uses a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means an annual (calendar year) period for an affected EGU to comply with a standard of performance.

Derate means a decrease in the available capacity of an electric generating unit, due to a system or equipment modification or to discounting a portion of a generating unit's capacity for planning purposes.

Fossil fuel means natural gas, petroleum, coal, and any form of solid fuel, liquid fuel, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gross energy output means:

(1) For stationary combustion turbines and IGCC, the gross electric or direct mechanical output from both the EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 100 percent of the useful thermal output.

(2) For steam generating units, the gross electric or mechanical output from the affected EGU(s) (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 100 percent of the useful thermal output;

(3) For combined heat and power facilities where at least 20.0 percent of the total gross energy output consists of useful thermal output on a 12-operating-month rolling average basis, the gross electric or mechanical output from the affected EGU (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to IGCC facilities), that difference divided by 0.95, plus 100 percent of the useful thermal output.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means 288 Kelvin (15 °C, 59 °F), 60 percent relative humidity and 101.3 kilopascals (14.69 psi, 1 atm) pressure.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour must be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Nameplate capacity means, starting from the initial installation, the maximum electrical generating output that a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer is capable of producing (in MWe, rounded to the nearest tenth) on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the equipment, or starting from the completion of any subsequent physical change resulting in an increase in the maximum electrical generating output that the equipment is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired,'' that is not a coal-fired or oil-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns natural gas for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual

heat input during any calendar year after December 31, 2029.

Net electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (*i.e.,* auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (*e.g.,* the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 100 percent of the useful thermal output measured relative to standard ambient temperature and pressure conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (*e.g.,* steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of the total gross or net energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross or net energy output consists of useful thermal output on a 12-operating month rolling average basis, the net electric or mechanical output from the affected EGU divided by 0.95, plus 100 percent of the useful thermal output; (*e.g.,* steam delivered to an industrial process for a heating application).

Oil-fired steam generating unit means an electric utility steam generating unit meeting the definition of ''fossil fuel-fired'' that is not a coal-fired steam generating unit, that no longer retains the capability to fire coal after December 31, 2029, and that burns oil for more than 10.0 percent of the average annual heat input during any continuous 3-calendar-year period after December 31, 2029, or for more than 15.0 percent of the annual heat input during any one calendar year after December 31, 2029.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25 °C, 77 °F) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

State agent means an entity acting on behalf of the State, with the legal authority of the State.

Stationary combustion turbine means all equipment including, but not limited to, the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system, or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. A stationary combustion turbine that burns any solid fuel directly is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

System Emergency means periods when the Reliability Coordinator has declared an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP–011–2, or its successor.

Uprate means an increase in available electric generating unit power capacity due to a system or equipment modification.

Useful thermal output means the thermal energy made available for use in any heating application (*e.g.,* steam delivered to an industrial process for a heating application, including thermal cooling applications) that is not used for electric generation, mechanical output at the affected EGU, to directly enhance the performance of the affected EGU (*e.g.,* economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output), or to supply energy to a pollution control device at the affected EGU. Useful thermal output for affected EGU(s) with no condensate return (or other thermal energy input to the affected EGU(s)) or where measuring the energy in the condensate (or other thermal energy input to the affected EGU(s)) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected EGU(s) with meaningful energy in the condensate return (or other thermal energy input to the affected EGU) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

Valid data means quality-assured data generated by continuous monitoring systems that are installed, operated, and maintained according to 40 CFR part 75. For CEMS, the initial certification requirements in 40 CFR 75.20 and appendix A to 40 CFR part 75 must be met before quality-assured data are reported under this subpart; for on-going quality assurance, the daily, quarterly, and semiannual/annual test requirements in sections 2.1, 2.2, and 2.3 of appendix B to 40 CFR part 75 must be met and the data validation criteria in sections 2.1.4, 2.2.3, and 2.3.2 of appendix B to 40 CFR part 75 apply. For fuel flow meters, the initial certification requirements in section 2.1.5 of appendix D to 40 CFR part 75 must be met before quality-assured data are reported under this subpart (except for qualifying commercial billing meters under section 2.1.4.2 of appendix D), and for on-going quality assurance, the provisions in section 2.1.6 of appendix D to 40 CFR part 75 apply (except for qualifying commercial billing meters).

Waste-to-Energy means a process or unit (*e.g.,* solid waste incineration unit) that recovers energy from the conversion or combustion of waste stream materials, such as municipal solid waste, to generate electricity and/or heat.

[FR Doc. 2024–09233 Filed 5–8–24; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL REGISTER

Vol. 89 Thursday,
No. 91 May 9, 2024

Part IV

Department of Health and Human Services

45 CFR Part 84
Nondiscrimination on the Basis of Disability in Programs or Activities Receiving Federal Financial Assistance; Final Rule

DEPARTMENT OF HEALTH AND HUMAN SERVICES

45 CFR Part 84

RIN 0945–AA15

Nondiscrimination on the Basis of Disability in Programs or Activities Receiving Federal Financial Assistance

AGENCY: U.S. Department of Health and Human Services.

ACTION: Final rule.

SUMMARY: The Department of Health and Human Services (HHS or the Department) is committed to protecting the civil rights of individuals with disabilities under section 504 of the Rehabilitation Act of 1973 (section 504). To implement the prohibition of discrimination on the basis of disability, the Department is making a number of revisions to update and amend its section 504 regulation.

DATES:

Effective date: This rule is effective July 8, 2024.

Incorporation by reference: The incorporation by reference of certain material listed in the rule is approved by the Director of the Federal Register as of July 8, 2024.

FOR FURTHER INFORMATION CONTACT: Molly Burgdorf, Office for Civil Rights, Department of Health and Human Services at (202) 545–4884 or (800) 537–7697 (TDD), or via email at *504@hhs.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Background
II. Overview of the Final Rule
III. Response to Public Comments on the Proposed Rule
IV. Executive Order 12866 and Related Executive Orders on Regulatory Review

I. Background

Section 504 of the Rehabilitation Act of 1973 prohibits discrimination on the basis of disability in programs and activities that receive Federal financial assistance as well as in programs and activities conducted by any Federal agency.[1]

The Office for Civil Rights (OCR) in HHS enforces section 504 as well as other statutes that prohibit discrimination on the basis of disability. Title II of the Americans with Disabilities Act (ADA) prohibits discrimination on the basis of disability in, among other areas, all health care and social services programs and activities of State and local government entities.[2] OCR also enforces section 1557 (section 1557) of the Patient Protection and Affordable Care Act (ACA) which prohibits discrimination on various bases, including disability, in any health program or activity, any part of which receives Federal financial assistance, including credits, subsidies, or contracts of insurance or under any program or activity that is administered by an Executive Agency or any entity established under title I of the ACA.[3]

Congress passed the Rehabilitation Act in 1973, and what was then the U.S. Department of Health, Education, and Welfare issued regulations to implement section 504 in 1977. Those regulations have rarely been amended.[4] In the more than 40 years since enactment of the regulations, major legislative and judicial developments have shifted the legal landscape of disability discrimination protections under section 504. These developments include multiple statutory amendments to the Rehabilitation Act, the enactment of the ADA and ADA Amendments Act of 2008 (ADAAA), passage of the ACA, and Supreme Court and other significant court cases. In addition, the Department is aware of specific manifestations of disability-based discrimination in recent years, for example, in the area of accessibility of information and communications technology.

Section 504 must be interpreted consistently with these developments and laws to ensure conformity with current law and to protect against discrimination on the basis of disability. To provide clarity for recipients and beneficiaries and to promote compliance, the Department is amending its existing section 504 regulation on nondiscrimination obligations for recipients of Federal financial assistance (part 84).[5]

[1] 29 U.S.C. 794.

[2] 42 U.S.C. 12132.

[3] 42 U.S.C. 18116.

[4] Amendments to the section 504 regulations over time have included changes such as addressing the withholding of medical care from infants with disabilities (changes that the Supreme Court invalidated in *Bowen* v. *Amer. Hosp. Ass'n,* 476 U.S. 610 (1986)); changes to the accessible building standards; and changes to the definition of ''program or activity'' to conform to the Civil Rights Restoration Act of 1987).

[5] The Department notes that on January 15, 2021, OCR posted on its website a Request for Information (RFI) addressing a number of disability discrimination issues under part 84 of section 504. The RFI was later withdrawn, without being published in the **Federal Register**. OCR subsequently received letters urging HHS to address the issues in the RFI.

II. Overview of the Final Rule

On September 14, 2023, the Department published a proposed rule to amend 45 CFR part 84, Discrimination on the Basis of Disability in Programs or Activities Receiving Federal Financial Assistance (88 FR 63392). The 60-day comment period ended on November 13, 2023. The final rule adopts the same structure and subparts as the proposed rule. We have made some changes to the proposed rule's provisions based on comments received. As discussed in the notice of proposed rulemaking (NPRM), to fulfill Congress's intent that title II of the ADA and section 504 be interpreted consistently, the rule contains provisions that mirror the corresponding provisions in the title II ADA regulation.

No substantive difference is intended, aside from denoting the singular or plural, when using the terms ''individual with a disability,'' ''people with disabilities,'' and ''person with a disability'' throughout this rule.

The Department is retaining several sections from the existing section 504 rule. Many of those retained sections contain terminology revisions. The current rule can be found at: *https://www.ecfr.gov/current/title-45/subtitle-A/subchapter-A/part-84.*

III. Response to Public Comments on the Proposed Rule

This section focuses on the provisions of the rule that are relevant to comments received, and the explanations necessary to address those comments. For a fuller explanation of the background and intended meaning of regulatory language in the final rule that remain unchanged from the NPRM, please refer to the discussion in the NPRM.

Subpart A—General Provisions

Subpart A sets forth the general provisions that apply to all recipients. Four of the sections from the existing regulation are retained without any changes, §§ 84.5 through 84.7 and 84.9. The remainder of the sections in this subpart are identical or similar to the ADA title II regulations.

Purpose and Broad Coverage (§ 84.1)

Proposed § 84.1(a) provided that the purpose of this regulation is to implement section 504, which prohibits discrimination on the basis of disability in any program or activity receiving Federal financial assistance.

Proposed § 84.1(b) stated that the definition of ''disability'' shall be construed broadly in favor of expansive coverage to the maximum extent

permitted by section 504. The primary objective of attention in cases should be whether recipients have complied with their obligations and whether discrimination occurred, and not whether the individual meets the definition of ''disability.'' The question of whether an individual meets the definition of ''disability'' should not demand extensive analysis.

The comments and our responses regarding § 84.1 are set forth below.

Comment: The Department received many comments applauding the inclusion of this section. Commenters expressed appreciation for the Department's commitment to construing the protection of the law broadly in favor of expansive coverage.

Response: The Department appreciates the commenters' input.

Summary of Regulatory Changes

We are finalizing § 84.1 as proposed with no modifications.

Application (§ 84.2)

Proposed § 84.2(a) provided that this part applies to each recipient of Federal financial assistance from the Department and to the recipient's programs and activities that involve individuals with disabilities in the United States. This part does not apply to the recipient's programs and activities outside the United States that do not involve individuals with disabilities in the United States.

Proposed § 84.2(b) provided that the requirements of this part do not apply to the ultimate beneficiaries of any program or activity operated by a recipient of Federal financial assistance.

Proposed § 84.2(c) provided that any provision of this part held to be invalid or unenforceable by its terms, or as applied to any person or circumstance, shall be construed so as to continue to give maximum effect to the provision permitted by law, unless such holding shall be one of utter invalidity or unenforceability, in which event the provision shall be severable from this part and shall not affect the remainder thereof or the application of this provision to other persons not similarly situated or to other dissimilar circumstances.

The comments and our responses regarding proposed § 84.2 are set forth below.

Comments: The Department received several comments asking for clarification of the types of entities covered by section 504. Many mentioned specific entities and asked whether they are covered. Others requested that the Department provide a list of all covered entities.

Response: Most of these commenters were essentially asking for a more detailed explanation of what constitutes ''Federal financial assistance,'' the prerequisite to section 504 coverage, than what appeared in the proposed rule's definition. The Department's interpretation of Federal financial assistance and the types of entities covered by this rule can be found in the discussion of Federal financial assistance contained at § 84.10, the definitions section of the rule.

Summary of Regulatory Changes

For the reasons set forth above and considering comments received, we are finalizing § 84.2 as proposed with no modifications.

Relationship to Other Laws (§ 84.3)

Proposed § 84.3 provided an explanation of the relationship of the proposed regulation to existing laws. The section provided that this part does not invalidate or limit remedies, rights, and procedures of any other Federal law, State, or local law that provides greater or equal protection for the rights of individuals with disabilities and individuals associated with them.

The comments and our responses to § 84.3 are set forth below.

Comments: The Department received many comments, including from multiple disability rights organizations, concerning the relationship of this regulation to other laws. Several commenters mentioned the importance of ensuring that laws providing more protection such as the ADA are not affected by this regulation. One commenter remarked that the principle encompassed in this section is fundamental to maintaining a comprehensive support system for individuals with disabilities as it recognizes that laws are layered and work together. Another commenter urged the Department to adopt this section to ensure that any new Federal requirements offer a floor, but not a ceiling, for the protection of disability rights. Many organizations representing individuals with disabilities asked the Department to clarify how this regulation interacts with section 1557.

Another commenter asked about the relationship of section 504 to State laws and whether Federal law always supersedes State law.

Response: The Department appreciates commenters' support for this provision. In developing this regulation, we have been closely coordinating within the Department on the section 1557 rule, and we will continue this close coordination on the impact of the 504 rule and its relationship to other applicable laws, including section 1557, in the future. We will consider developing guidance and technical assistance as needed on these topics in the future.

As for whether Federal laws always supersede State laws, we note that standard principles of preemption apply under section 504.

Summary of Regulatory Changes

For the above reasons and considering comments received, we are finalizing § 84.3 as proposed with no modifications.

Disability (§ 84.4)

Proposed § 84.4 provided a detailed definition of disability implementing the ADAAA, which amended section 504 to adopt the ADAAA definition of disability. The proposed rule largely incorporated the definition contained in the ADA title II regulation and was intended to ensure consistency between the ADA and section 504. The only differences between the definition of disability in § 84.4 and the definition of disability in the ADA title II regulation were updates in terminology and the addition of long COVID, a condition that did not exist when the ADA regulation was published, to the list of physical and mental impairments.

Proposed § 84.4(a)(1) stated that, with respect to an individual, disability means a physical or mental impairment that substantially limits one or more of the major life activities of such individual; a record of such an impairment; or being regarded as having such an impairment. Proposed § 84.4(a)(2) stated that the definition of disability shall be construed broadly in favor of expansive coverage to the maximum extent permitted by the terms of section 504.

Proposed § 84.4 provided detailed definitions of the terms used in § 84.4(a)(1). It defined physical or mental impairment (§ 84.4(b)), major life activities (§ 84.4(c)), substantially limits (§ 84.4(d)), has a record of such an impairment (§ 84.4(e)), is regarded as having such an impairment (§ 84.4(f)), and it included a list of conditions excluded from the definition (§ 84.4(g)). At § 84.4(d)(2), it provided a list of predictable assessments, circumstances where the inherent natures of the specific impairments will, as a factual matter, virtually always be found to impose a substantial limitation on a major life activity, and for which the necessary individualized assessment should be particularly simple and straightforward (*e.g.,* deafness substantially limits hearing).

At proposed § 84.4(b)(2), the rule included long COVID as a physical or mental impairment. This inclusion follows guidance issued on July 26, 2021, from the Department of Justice (DOJ) and HHS on how long COVID can be a disability under the ADA, section 504, and section 1557.[6]

When the Department proposed section 84.4(g), it addressed exclusions from section 504 coverage by taking language directly from the text of the Rehabilitation Act.[7] Section 84.4(g) now states that the term ''disability'' does not include the terms set forth at 29 U.S.C. 705(20)(F). That statutory text excludes gender identity disorders not resulting from physical impairments from the definition of disability. The Department noted in the preamble of the proposed rule that an individual with gender dysphoria may have a disability under section 504 and that restrictions that prevent, limit, or interfere with otherwise qualified individuals' access to care due to their gender dysphoria, gender dysphoria diagnosis, or perception of gender dysphoria, may violate section 504.

The comments and our responses to § 84.4 are set forth below.

Comments: Commenters expressed strong support for the Department's revised definition of disability, for complying with the ADAAA, and for ensuring consistency with the Department of Justice's ADA regulatory definition of disability. Commenters also expressed approval for the specific inclusion of long COVID as a physical or mental impairment.

Response: Accordingly, the Department has retained the approach and language of its proposed rule in this final rule and has retained the inclusion of long COVID as a physical or mental impairment.

Physical and Mental Impairments (§ 84.4(b))

Comments: Although expressing support for the Department's expansion of its definition of disability, a number of commenters suggested adding specific conditions to the text of § 84.4(b). These commenters suggested specifically including in the regulatory text a number of conditions as impairments, including, for example: obesity, hepatitis B, hepatitis C, endometriosis, developmental disabilities, intersex variations, and chemical and electromagnetic hypersensitivities (including allergies to fragrances). One commenter noted that ''autism'' was not included in the list of impairments, but that Autism Spectrum Disorder was included in § 84.4(d)(2)(iii)(E). The comments included descriptions of the discrimination faced by persons with these conditions and how inclusion in the Department's section 504 regulation would provide a vehicle for their active participation in programs and activities funded by the Department.

Response: The Department notes that the list of disorders and conditions in § 84.4(b) is non-exhaustive and illustrative. The preamble to the DOJ's title II ADA regulation explains why there was no attempt to set forth a comprehensive list of physical and mental impairments. That preamble states ''[i]t is not possible to include a list of all the specific conditions, contagious and noncontagious diseases, or infections that would constitute physical or mental impairments because of the difficulty of ensuring the comprehensiveness of such a list, particularly in light of the fact that other conditions or disorders may be identified in the future.'' [8] The Department shares this view. Failure to include any specific disorder or condition does not mean that that condition is not a physical or mental impairment under section 504 or the rule. No negative implications should be drawn from the omission of any specific impairment in the list of impairments in § 84.4(b). In fact, the Department notes that its rule of construction for the definition of disability is that the definition of disability is to be construed broadly in favor of expansive coverage to the maximum extent permitted by the terms of section 504.

As a result, the Department has decided not to add any further specific disorders or conditions to the regulatory text of § 84.4(b). This approach has the added benefit of ensuring a consistent interpretation of this important statutory term that is shared by both section 504 and both titles II and III of the ADA and avoids any confusion that might result from having related Federal disability rights regulations with different language for the same term.

The Department wishes to make clear, however, that the conditions proffered by commenters may constitute a physical or mental impairment as that term is used in section 504. For example, obesity, without any accompanying comorbidities, may be included in the phrase ''any physiological disorder or condition'' and thus constitute a physical impairment for higher-weight individuals. Similarly, intersex variations may result from physical conditions that are structured or function differently from most of the population and affect the endocrine, reproductive, and/or genitourinary systems of an individual, or may be evidenced by anatomical loss affecting one or more of the body's systems, and thus be included within the phrase ''any physiological disorder or condition.'' The Department received comments asking that we add other, specific conditions to the list of physical and mental impairments. While many conditions may constitute a physical or mental impairment as that term is used in section 504, it is not necessary for the Department to add these conditions to the rule as the Department's list is not an exhaustive list.

Of course, being included as a physical or mental impairment does not mean that a particular individual has a disability covered by section 504. To be covered by section 504 and Department's final rule, the impairment must then substantially limit one or more of the person's major life activities. In addition, section 504 coverage could be established for a particular individual if that person has a record of the impairment that substantially limited one of more of their major life activities; or if they were subjected to a prohibited action because of an actual or perceived physical or mental impairment, whether or not that impairment substantially limits, or is perceived to substantially limit, a major life activity.

Gender Dysphoria

Comments: The preamble of the Department's NPRM included in its analysis of § 84.4(g), Exclusions, a discussion of section 504's exclusion of gender identity disorders not resulting from physical impairments, and a recent Fourth Circuit case, *Williams* v. *Kincaid,*[9] concluding that gender dysphoria can be a disability under section 504 and the ADA. In the NPRM, the Department agreed with the Fourth Circuit's recent holding that gender dysphoria may constitute a disability under section 504 and that restrictions that prevent, limit, or interfere with otherwise qualified individuals' access to care due to their gender dysphoria, gender dysphoria diagnosis, or

[6] *See* U.S. Dep't of Health & Human Servs., U.S. Dep't of Justice, Guidance on ''Long COVID'' as a Disability Under the ADA, section 504, and section 1557 (July 26, 2021), *https://www.hhs.gov/civil-rights/for-providers/civil-rights-covid19/guidance-long-covid-disability/index.html.*

[7] 29 U.S.C. 705(20)(F).

[8] 28 CFR part 35, appendix B.

[9] *Williams* v. *Kincaid,* 45 F.4th 759 (4th Cir. 2022, cert. denied, 600 U.S. ____ (June 30, 2023) (No. 22–633).

perception of gender dysphoria may violate section 504.

The inclusion of this discussion in the preamble elicited a robust discussion from commenters. Comments from civil rights and patient advocacy organizations representing persons with disabilities supported the concept of coverage of gender dysphoria in the section 504 rule but sought changes that would strengthen the Department's inclusion of gender dysphoria by including specific regulatory text (*e.g.,* by making clear that gender dysphoria is not included within the scope of gender identity disorders) and by expanding and clarifying protections.

Commenters representing certain religious organizations and some State officials, among others, objected to the Department's conclusion that gender dysphoria can be a disability covered under section 504. The comments asserted that the *Kincaid* decision is only one court decision, that the dissent in the case was more compelling, and that the Department has ignored contrary court decisions.[10] These commenters stated that the Department's view could adversely impact them because section 504 does not have an exemption for religious entities. In the alternative, the commenters sought significantly more detail regarding what actions will be prohibited or required by inclusion of the language.

Response: As noted above, the Department's section 504 NPRM preamble noted that gender dysphoria may constitute a disability under section 504 and that restrictions that prevent, limit, or interfere with otherwise qualified individuals' access to care due to their gender dysphoria, gender dysphoria diagnosis, or perception of gender dysphoria may violate section 504.

In the *Williams* case, the only Federal appellate court to consider the issue of coverage for gender dysphoria under section 504 and the ADA concluded that the language excluding gender identity disorders from coverage did not encompass gender dysphoria. The Fourth Circuit reversed and remanded the district court's dismissal of the case, holding that the plaintiff ''has plausibly alleged that gender dysphoria does not fall within section 504's and the ADA's exclusion for ''gender identity disorders not resulting from physical impairments.'' [11] The court noted that the term ''gender dysphoria'' was not used in section 504 or the ADA nor in the then current version of the Diagnostic and Statistical Manual of Mental Disorders (DSM). In 2013, the phrase was changed in the DSM from ''gender identity disorder'' to ''gender dysphoria,'' a revision that the court said was not just semantic but reflected a shift in medical understanding. The court reasoned that gender dysphoria is not included in the scope of the exclusion for ''gender identity disorders,'' but that even if gender dysphoria were such a disorder, plaintiff's complaint ''amply supports [the] inference'' that her gender dysphoria ''result[s] from a physical impairment.'' [12]

Recognizing ''Congress' express instruction that courts construe the ADA in favor of maximum protection for those with disabilities,'' [13] the court said that it saw ''no legitimate reason why Congress would intend to exclude from the ADA's protections transgender people who suffer from gender dysphoria.'' [14] The Department agrees with the court's holding that restrictions that prevent, limit, or interfere with otherwise qualified individuals' access to care due to their gender dysphoria, gender dysphoria diagnosis, or perception of gender dysphoria may violate section 504.[15]

The Department will approach gender dysphoria as it would any other disorder or condition. If a disorder or condition affects one or more body systems, or is a mental or psychological disorder, it may be considered a physical or mental impairment. The existing section 504 rule includes the following as body systems: ''neurological, musculoskeletal, special sense organs, respiratory (including speech organs), cardiovascular, reproductive, digestive, genitourinary, immune, circulatory, hemic, lymphatic, skin, and endocrine.'' The issue before the Department then is whether gender dysphoria is a condition that can affect any bodily system or is a mental or psychological condition. Such an inquiry is necessarily a fact-based, individualized determination but the Department agrees with the Fourth Circuit that gender dysphoria can satisfy this standard. A determination in an individual situation that gender dysphoria is a physical or mental impairment is, of course, not the end of the question. It must then be determined whether the impairment substantially limits any major life activity. Depending on that analysis, gender dysphoria may rise to the level of a disability under section 504 and would provide protection against discrimination in programs or activities funded by HHS that is prohibited by section 504.

As to the lower court cases that held that gender dysphoria is included within the definition of gender identity disorders, the Department believes that the conclusion the Fourth Circuit reached in the *Williams* case and the view expressed in the United States' Statement of Interest in *Doe* v. *Georgia Department of Corrections* reflect the more compelling reading of the statute. That interpretation is that, when Congress enacted the ADA in 1990, ''gender identity disorders'' referred to a person's mere identification with a different gender than the sex they were assigned at birth, a condition that is not a disability. Gender dysphoria, by contrast, may be a disability, one that is characterized by clinically significant distress or impairment in social, occupational, or other important areas of functioning; thus gender dysphoria does not fall with the statutory exclusions for gender identity disorders.[16]

As to concerns about religious freedom and conscience, the section 504 rule does not contain provisions on those issues. However, the Department does have other statutes and regulations that apply protections in these areas. For example, in January 2024, the Department finalized a rule clarifying the Department's enforcement of the Federal health care conscience statutes, including that OCR receives and handles complaints regarding these statutes.[17] The Department will comply with all applicable law. We decline to make changes to this rule.

Major Life Activities (§ 84.4(c))

Comments: In the Department's NPRM, proposed § 84.4(c) significantly expanded the range of major life

[10] *See, e.g., Duncan* v. *Jack Henry & Assocs., Inc.,* 617 F. Supp. 3d 1011, 1055–57 (W.D. Mo. 2022); *Lange* v. *Houston Cnty.,* 608 F. Supp. 3d 1340, 1362 (M.D. Ga. 2022); *Doe* v. *Northrop Grumman Sys. Corp.,* 418 F. Supp. 3d 921 (N.D. Ala. 2019); *Parker* v. *Strawser Constr. Inc.,* 307 F. Supp. 3d 744, 754–55 (S.D. Ohio 2018); *Gulley-Fernandez* v. *Wis. Dep't of Corr.,* 2015 WL 7777997, at *3 (E.D. Wis. Dec. 1, 2015); *but see Doe* v. *Mass. Dep't of Corr.,* 2018 WL 2994403 (D. Mass. Jun. 14, 2018); *Blatt* v. *Cabela's Retail, Inc.,* 2017 WL 2178123 (E.D. Pa. May 18, 2017); *Guthrie* v. *Noel,* 2023 WL 8115928, at *13 (M.D. Pa. Sept. 11, 2023).

[11] *Id.* at 780.

[12] *Id.* at 773–74 (citing 42 U.S.C. 12211(b)); *see also id.* at 770–72.

[13] *Id.* at 769–70.

[14] *Id.* at 773.

[15] The Department's interpretation is also consistent with the position taken by the Department of Justice's Civil Rights Division on the proper interpretation of ''gender identity disorders'' under the ADA and section 504. *See* Statement of Interest, *Doe* v. *Ga. Dep't of Corr.,* No. 23–5578 (N.D. Ga. Jan. 8, 2024), ECF No. 69.

[16] *See also* Am. Psychiatric Ass'n, *Diagnostic and Statistical Manual of Mental Disorders* (5th ed. text rev. 2022), *https://perma.cc/U4KQ-HA98.*

[17] 89 FR 2078 (Jan. 11, 2024).

activities in the current rule in response to the ADAAA and DOJ's ADA rules, specifically including major bodily functions and providing an expanded non-exhaustive list of examples of major life activities. It also indicated that ''major'' should be interpreted in a more expansive fashion than previously. Commenters supported the Department's approach to defining and interpreting the term ''major life activities,'' but suggested that the Department should add to the list. One commenter suggested that the major life activity of ''caring for oneself'' was too narrow in scope and that should be expanded to address caring for other family members, taking care of pets or service animals, and caring for guests or visitors to the home, noting that caring for others, no matter what the relationship, is a common major life activity. Another commenter suggested including recognition of mental health and cognitive abilities in this section.

Response: The Department appreciates these comments but has determined it is not necessary to add these or any other new terms to the list of major life activities in § 84.4(c). This list is, by its own terms, not exhaustive and thus other activities can certainly be considered major life activities. The Department also wants to avoid any confusion that may be caused by including terms in this regulatory language that are different than those found in the parallel sections defining disability under the ADA and titles II and III of the ADA regulations of DOJ and under title I of the ADA and the regulations of the Equal Employment Opportunity Commission (EEOC).

As for the coverage of mental health issues, the Department notes the inclusion of learning, concentrating, and thinking as major life activities in § 84.4(c)(1)(i) and the operation of neurological systems as a major bodily function in § 84.4(c)(1)(ii). Further, because mental health and cognitive capability are central to functioning and well-being, impairment in either may significantly impact major life activities such as working, sleeping, and caring for oneself or others.

Predictable Assessments

Comments: Commenters noted that the list of examples in § 84.4(d)(2)(iii), when referring to the Human Immunodeficiency Virus (HIV) infection, did not include the phrase ''whether symptomatic or asymptomatic'' even though that phrase was included in the list of physical or mental impairments in § 84.4(b)(2) and requested that the phrase be added in the final rule.

Response: The Department agrees with the commenters that persons who have HIV are substantially limited in their immune function, whether or not they present with symptoms of the disease. Section 84.4(d)(2)(iii)(J) of this rule includes HIV, and the provision of predictable assessments presumptively covers persons who have HIV, whether or not they are symptomatic. The Department also recognizes the need to have its regulatory provision here be consistent with the ADA's parallel regulation on the definition of disability, which does not include the phrase ''whether symptomatic or asymptomatic'' in the provision on predictable assessments. As a result, the Department will not add this phrase to the paragraph on predictable assessments to avoid any confusion that may result from having Federal regulations with different terminology on the same issue.

Outdated and Offensive Terminology

Comments: Commenters were uniformly supportive of changing the terminology in the Department's existing section 504 rule from the use of ''handicap'' and ''handicapped individual'' to ''disability'' and ''individual with a disability.'' One comment noted that this change from ''handicap'' to ''disability'' was more than just terminology and that it reflected issues overlaid with stereotypes, patronizing attitudes, and other emotional connotations. Commenters were also uniformly supportive of changing the terminology in the list of physical and mental impairments in § 84.4(b)(2), and throughout the rule, from ''drug user'' to ''individual with a substance use disorder'' and ''alcoholic'' to ''individual with an alcohol use disorder.'' Some commenters, however, objected to use of the phrase ''emotional or mental illness'' because it carries significant stigma, and suggested the use of more neutral terminology, such as ''person with a mental health condition.'' Other commenters objected to the terminology used in § 84.4(g) on exclusions from coverage and suggested that the section be removed in its entirety.

Response: The Department is aware that some of the terms used in its regulation have come to be understood, in common parlance, as having negative connotations or being pejorative.

The terms that the Department proposed in the regulatory provision on exclusions, § 84.4(g), are taken verbatim from the Rehabilitation Act at 29 U.S.C. 705(20)(F). Those terms had specific meanings when Congress added them to the statute decades ago and the Department is bound by these statutory exclusions. However, the Department appreciates that the terminology used in this section of the statute is now considered offensive to many communities. As such, we are revising the final section at § 84.4(g) to cite to the relevant statutory text. This is a non-substantive change; the Department is still bound by the statutory exclusions cited at § 84.4(g).

With regard to the use of the terms ''emotional or mental illness'' in § 84.4(b)(1)(ii) and ''emotional illness'' in § 84.4(b)(2), the Department is substituting the neutral term ''mental health condition.'' Both the terms ''emotional or mental illness'' and ''emotional illness'' are used in the definition of impairments contained in the definition of ''disability'' in § 84.4(b). These terms are found in the ADA titles II and III regulations as well as in the EEOC regulations for title I of the ADA. Because these terms are regulatory, not statutory, the Department believes it appropriate in these circumstances to change the language to address usage concerns. The term ''mental health condition'' is neutral terminology that may help to reduce the negative connotations for people experiencing mental health conditions. The Department itself now uses the phrase ''mental health condition'' instead of emotional or mental illness in other contexts. The Department intends no difference in meaning with this new term and it will be interpreted consistently with the terms ''emotional or mental illness'' or ''emotional illness'' in the parallel ADA titles II and III regulations.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.4 as proposed with three modifications. First, we are replacing the phrase ''emotional or mental illness'' with ''mental health condition'' in § 84.4(b)(1)(ii). Second, we are replacing the phrase ''emotional illness'' with ''mental health condition'' in § 84.4(b)(2). Third, we are replacing a list of terms at § 84.4(g) with a citation to the relevant passage of the statute that enumerates exclusions.

Notice (§ 84.8)

Proposed § 84.8 required recipients to make available to employees, applicants, participants, beneficiaries, and other interested persons information about this part and its applicability to the recipient's programs and activities, and to make the information available to them in such

manner as the head of the agency or their designee finds necessary to apprise such persons of the protections against discrimination assured them by section 504 and this part.

The comments and our responses regarding § 84.8 are set forth below.

Comment: A commenter asked whether a statement on a website about both the ADA and section 504 is enough and whether this notice requirement is different from the current requirements. Another commenter asked whether recipients are required to prominently post the notice and provide information about filing a complaint.

Response: This notice requirement is identical to the notice requirement in the ADA title II regulations. Recipients are required to disseminate sufficient information to applicants, participants, beneficiaries, and other interested persons to inform them of the rights and protections afforded by section 504 and this regulation. Methods of providing this information include, for example, the publication of information in handbooks, manuals, and pamphlets that are distributed to the public, including online material, to describe a recipient's programs and activities; the display of informative posters in service centers or other public places; or the broadcast of information by television or radio. In providing the notice, the recipient must comply with the requirements for effective communication in § 84.77. The preamble to that section, along with the preamble from the NPRM, gives guidance on how to effectively communicate with individuals with disabilities.

In response to the question of whether the existing notice requirements in § 84.8 are different than those in this final rule, the biggest difference is that the existing regulations only apply to recipients with fifteen or more employees. In addition, the existing notice provisions provide more detailed requirements than are contained in this final rule. For example, the existing notice section requires an identification of the responsible employee designated pursuant to § 84.7(a). It also sets forth requirements for when the notice must be published, methods of publishing, and the types of documents that must contain the notice requirement.

There is another notice provision at § 84.52(b) in subpart F, Health, Welfare, and Social Services, which we are retaining. That section states that a recipient that provides notice concerning benefits or services or written material concerning waivers of rights or consent to treatment shall take such steps as are necessary to ensure that qualified individuals with disabilities, including those with impaired sensory or speaking skills, are not denied effective notice because of their disability.

Section 84.7, Designation of responsible employee and adoption of grievance procedures, is retained in the final rule. Section 84.7(a) requires that recipients with fifteen or more employees designate at least one person to coordinate their efforts to comply with this part. Section 84.7(b) requires those recipients to adopt grievance procedures that incorporate due process standards and that provide for the prompt and equitable resolution of complaints. Although not required, we recommend that notices contain information about the coordinator and about the grievance procedures.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.8 as proposed with no modifications.

Definitions (§ 84.10)

In § 84.10 of the proposed rule, we set out proposed definitions of various terms. The comments and our responses are set forth below. Unless otherwise indicated, the definitions are retained as proposed.

Auxiliary Aids and Services

Discussion of this term can be found at § 84.77.

Archived Web Content

The proposed rule defined ''archived web content'' as ''web content that is maintained exclusively for reference, research, or recordkeeping, is not altered or updated after the date of archiving, and is organized and stored in a dedicated area or areas clearly identified as being archived.''

Comment: Some commenters requested clarity on the definition of archived web content. Some of these commenters stated that the word ''maintain'' could have multiple meanings, such as simply continuing possession or engaging in repair and upkeep.

Response: The Department added a new part to the definition to help clarify the scope of content covered by the definition and associated exception. The new part of the definition, the first part, specifies that archived web content is limited to three types of historic content: web content that was created before the date the recipient is required to comply with subpart I; web content that reproduces paper documents created before the date the recipient is required to comply with subpart I; and web content that reproduces the contents of other physical media created before the date the recipient is required to comply with subpart I.

In addition to adding a new first part to the definition of archived web content, the Department made one further change to the definition from the NPRM. In the NPRM, what is now the second part of the definition pertained to web content that is ''maintained'' exclusively for reference, research, or recordkeeping. In the final rule, the word ''maintained'' is replaced with ''retained.'' The revised language is not intended to change or limit the coverage of the definition. Rather, the Department recognizes that the word ''maintain'' can have multiple meanings relevant to this rule. In some circumstances, ''maintain'' may mean ''to continue in possession'' of property, whereas in other circumstances it might mean ''to engage in general repair and upkeep'' of property.[18] In contrast, the third part of the definition states that archived web content must not be altered or updated after the date of archiving. Such alterations or updates could be construed as repair or upkeep, but that is not what the Department intended to convey with its use of the word ''maintained'' in this provision. To avoid confusion about whether a recipient can alter or update web content after it is archived, the Department instead uses the word ''retained,'' which has a definition synonymous with the Department's intended use of ''maintain'' in the NPRM.[19]

Additional discussion of this term can be found at § 84.85(a).

Companion

The proposed rule defined a ''companion'' as ''a family member, friend, or associate of an individual seeking access to a program or activity of a recipient, who, along with such individual, is an appropriate person with whom the recipient should communicate.'' The same definition is contained in the general section of the communications subpart at § 84.77(a)(2).

Comments: Representatives from many disability rights organizations commented that the definition needs greater clarity. They said that it is critical that recipients confirm the companion's role and, as appropriate, obtain consent from the individual with a disability that they want the

[18] *Maintain,* Black's Law Dictionary (11th ed. 2019).

[19] *See Retain,* Black's Law Dictionary (11th ed. 2019) (''To hold in possession or under control; to keep and not lose, part with, or dismiss.'').

companion to participate in their care. Some commenters noted that this concern is discussed somewhat in the communications section, but they suggested that it be made clear that these standards apply in all situations.

A disability rights organization asked that we clarify that the determination as to who is an appropriate companion must rest with the individual with a disability (or their designated decision-maker pursuant to State law) and not with the recipient. They expressed the view that that this is critically important because to not do so might violate privacy laws and may also undermine the autonomy of people with disabilities. They requested that the clarification language be added to the text of the regulation.

Another disability rights organization similarly requested changes to the regulatory text. They objected to the use of the term ''companion,'' which they believed is based on the stereotype that treats all individuals with disabilities as eternal children who must have a companion to communicate with recipients. They also objected to the term because it implies that the companion is communicating with the recipient independently rather than revoicing or repeating what the person with disabilities wants to be expressed and understood. According to the organization, this perpetuates an endemic and unhealthy form of disability-based discrimination expressed in all facets of society, but especially in health care. Commenters suggested replacement of the term ''companion'' with the term ''communication intermediary'' or an equivalent term that more accurately describes the role. Their suggested definition for the new term is a person who assists an individual with a disability to effectively communicate, to be understood, and to understand others. The role of this person is to relay information. Recipients must communicate with the individual with a disability directly and respectfully, and they may not use the presence of the other person as a reason to evade that obligation.

Response: We decline to revise the regulatory text, which is the same that appears in the ADA title II regulations at 28 CFR 35.160(a)(2). While we appreciate commenters' concerns, the definition makes clear that the companion must be ''an appropriate person with whom the public entity should communicate.'' Consistent with the title II regulation, this means the companion must be ''someone with whom the public entity normally would or should communicate'' in the situation at hand.[20] This requirement ensures that companions with disabilities receive effective communication even if the person that the companion accompanies is not an individual with a disability. As to the commenter who wanted a change in the word ''companion'' and provided language to describe the duties of that person, we do not believe that revisions in the text are needed, and it is beyond the scope of the Department's responsibility as the person with a disability will determine the appropriate duties for their companion. Accordingly, we decline to revise the definition of companion.

Conventional Electronic Documents

Discussion of this term can be found in subpart I. The Department is deleting ''database file formats'' from the definition.

Current Illegal Use of Drugs

The proposed rule said that ''current illegal use of drugs'' means illegal use of drugs that occurred recently enough to justify a reasonable belief that a person's drug use is current or that continuing use is a real and ongoing problem. This definition is identical to the one in the ADA title II regulations.

Comments: The Department received many comments on this definition. They uniformly had the same concern about the meaning of ''current.'' Many commenters said that the definition, which comes from ADA regulations, is antiquated and does not take into account the importance of understanding that for people with substance use disorders, recurrence of use is common and it does not mean the treatment is not or will not be successful. Instead, in many cases it may mean that the current treatment plan is not working and should be revisited and revised. Commenters maintained that without an expansive and nuanced consideration of the non-linear nature of treatment and recovery, including possible recurrent use, protections for people with substance use disorders (SUD) are incomplete and inappropriately distinguished from other forms of disability.

Response: The Department appreciates all commenters' feedback. The Department acknowledges commenters' concerns. However, the phrase ''illegal use of drugs'' is used in both the ADA and the Rehabilitation Act. Congress' intended meaning for the phrase is clear. As explained in the preamble to the title II ADA regulations, the definition of ''current illegal use of drugs'' is based on the report of an ADA Conference Committee, H.R. Conf. Rep. No. 596, 101st Cong., 2d Sess. 64 (1990). That Report says that ''current illegal use of drugs'' is use ''that occurred recently enough to justify a reasonable belief that a person's drug use is current or that continuing use is a real and ongoing problem.'' Both the ADA and the Rehabilitation Act define ''individual with a disability'' as not including an individual who is currently engaging in the illegal use of drugs when a covered entity or recipient acts on the basis of such use.

We therefore decline to revise the definition of ''current illegal use of drugs.''

Direct Threat

The proposed rule said that ''direct threat'' means a significant risk to the health or safety of others that cannot be eliminated by a modification of policies, practices, or procedures, or by the provision of auxiliary aids or services. With respect to employment, the term is as defined by the Equal Opportunity Commission's regulation implementing title I of the Americans with Disabilities Act of 1990, at 29 CFR 1630.2(r) (*https://www.ecfr.gov/current/title-29/section-1630.2#p-1630.2(r)*).

Comment: The Department received comments from many disability rights organizations recommending revisions to the term ''direct threat'' as defined by the EEOC pursuant to its authority under title I of the ADA. In addition, they objected to the statement in the proposed rule's preamble that a person who poses a direct threat is not ''qualified.''

Many commenters said that whether an individual is qualified is a threshold question for a person with a disability to establish, whereas whether an individual poses a direct threat is an affirmative defense for a recipient to establish. They recommended that we apply the direct threat analysis as set out in the ADA title II regulations and they provided a sentence that they would like inserted in the preamble.

Response: We appreciate the commenters' feedback. We note, however, that the Department has no authority to change the definition in EEOC regulations promulgated under title I of the ADA.

The definition of ''direct threat'' set forth in proposed paragraph (1) was added to be consistent with the ADA title II regulation and with the Supreme Court case of *School Board of Nassau County* v. *Arline.*[21] As to the request that we insert the commenters'

[20] 28 CFR part 35, appendix A at 668 (2023).

[21] 480 U.S. 273 (1987).

suggested language into the commentary, we reiterate the statement in the NPRM preamble, which also mirrors appendix B to the ADA title II regulation, that ''[a]lthough persons with disabilities are generally entitled to the protection of this part, a person who poses a significant risk to others constituting a direct threat will not be 'qualified' if reasonable modifications to the recipient's policies, practices, or procedures will not eliminate that risk.'' It is important that the interpretation of ''direct threat'' in paragraph (1) of this rule and its interpretation in the ADA title II regulations be consistent. Accordingly, we decline to revise the definition of ''direct threat.''

Facility

The proposed rule defined ''facility'' as ''all or any portion of buildings, structures, sites, complexes, rolling stock or other conveyances, roads, walks, passageways, parking lots, or other real or personal property, including the site where the building, property, structure, or equipment is located.''

Comment: A commenter representing persons with disabilities suggested adding language to address drive-through services. The comment notes that courts have resisted accessibility requirements for drive-through services and that drive-throughs are an important point of access for obtaining prescription medication and were a first line of service at the start of the COVID pandemic. The comment recommended including ''product or service dispersing facilities and drive-throughs'' in the list of items that constitute a facility.

Response: The Department believes it is not necessary to include any new regulatory text because the facility housing drive-through services is already included within the expansive text of the existing language. Facility includes buildings, structures, passageways, and equipment, which will cover all the areas that constitute the drive-through facility. In addition, if offered, drive-through services are a part of the recipient's program or activity and all the provisions of the section 504 rule will apply to this service, ensuring that persons with disabilities have access to this service.

We have retained the proposed definition of ''facility.''

Federal Financial Assistance

The proposed rule provided a detailed definition of ''Federal financial assistance'' as any grant, cooperative agreement, loan, contract (other than a direct Federal procurement contract or contract of insurance or guaranty), subgrant, contract under a grant or any other arrangement by which the Department provides or otherwise makes available assistance in the form of funds, services of Federal personnel, real or personal property or any interest in or use of such property, or any other thing of value by way of grant, loan, contract, or cooperative agreement. This definition is consistent with the definition in the existing regulation, with addition of ''direct Federal'' so that it reads ''(other than a direct Federal procurement contract or a contract of insurance or guaranty)''. No substantive change is intended from the existing definition.

Comment: Several commenters asked that the Department make clear that tax-exempt status is not ''Federal financial assistance'' and thus does not trigger the application of section 504. They noted that several recent cases brought under title IX have held that tax-exempt status is ''Federal financial assistance.'' [22] They also state that most other cases that have addressed whether tax-exempt status constitutes Federal financial assistance for purposes of statutes triggered by the receipt of such aid have held that tax-exempt status is not Federal financial assistance and thus does not trigger coverage of the statute in question.

Response: Generally, tax benefits, tax exemptions, tax deductions, and most tax credits are not included in the statutory or regulatory definitions of Federal financial assistance.[23] While a few courts have held that tax-exempt status can constitute Federal financial assistance, most courts that have considered the issue have concluded that typical tax benefits are not Federal financial assistance because they are not contractual in nature.[24] Accordingly, this Department generally does not consider tax exempt status to constitute Federal financial assistance. However, the definition of ''Federal financial assistance'' makes clear that Federal financial assistance that the Department plays a role in providing or administering is considered Federal financial assistance under this rule.

Comment: A commenter asked the Department to confirm that the definition of Federal financial assistance in this rule does not limit the scope of its proposed revision of regulations implementing section 1557. If finalized as proposed, the section 1557 regulations would, consistent with the ACA, define ''Federal financial assistance'' to include grants, loans, and other types of assistance from HHS, as well as credits, subsidies and contracts of insurance in accordance with the text of section 1557.[25]

Response: Section 1557 is a separate statute from section 504 and its regulation contains a more expansive definition of Federal financial assistance than section 504 does.[26] The definition of Federal financial assistance in this regulation does not constrain or otherwise limit the definition of Federal financial assistance under the Department's section 1557 regulations.

Comment: One commenter asked that the Department provide guidance on whether section 504 requirements apply to State Medicaid programs and managed care plans with which State agencies contract to administer Medicaid services to beneficiaries.

Response: When HHS provides Federal financial assistance, including grants, to an entity, section 504 obligations attach with the receipt of the funds. In essence this relationship is in the form of a contract between the Federal Government and the recipient, by which the recipient states that it will not discriminate on the basis of disability in its operation of its programs or activities as a condition of the receipt of Federal funds.[27] When the recipient contracts out responsibilities under the grant program or disburses the funds to other subgrantees that will also operate the program or activity, these statutory and contractual obligations pass down to the subgrantee or subcontractor.

[22] *See E.H.* v. *Valley Christian Acad.,* 616 F.Supp.3d 1040 (C.D. Cal. 2022); *Buettner-Hartsoe* v. *Baltimore Lutheran High Sch. Ass'n,* No. RDB–20–3132, 2022 WL 2869041 (D. Md. Jul. 21, 2022) *E.H.* v. *Valley Christian Acad.,* 616 F.Supp.3d 1040 (C.D. Cal. 2022).

[23] *See, e.g.,* 42 U.S.C. 2000d–1; 28 CFR. 42.102(c); 31 CFR 28.105. *See also* U.S. Dep't of Justice, Title VI Legal Manual, sec. V.C.

[24] *See, e.g., Paralyzed Veterans of Am.* v. *Civil Aeronautics Bd.,* 752 F.2d 694, 708–09 (DC Cir. 1985); *Johnny's Icehouse, Inc.* v. *Amateur Hockey Ass'n of Ill.,* 134 F. Supp. 2d 965, 971–72 (N.D. Ill. 2001); *Chaplin* v. *Consol. Edison Co.,* 628 F. Supp. 143, 145–46 (S.D.N.Y. 1986); *Bachman* v. *Am. Soc'y of Clinical Pathologists,* 577 F. Supp. 1257, 1264–65 (D.N.J. 1983).

[25] *See* ''Nondiscrimination in Health Programs and Activities,'' 87 FR 47824, 47912 (Aug. 4, 2022).

[26] *Id.* The existing 1557 regulation at 45 CFR 92.3(a)(1) (2020) also includes including credits, subsidies, or contracts of insurance provided by the Department.

[27] *See* 45 CFR 84.5 (''An applicant for Federal financial assistance to which this part applies shall submit an assurance, . . . that the program or activity will be operated in compliance with this part.'')

In the case of the Department's Medicaid program, State Medicaid programs receive Federal funds and are therefore covered by section 504.[28] When the State Medicaid agency provides Medicaid funds to managed care plans to manage and operate specific Medicaid programs or activities, those managed care plans are also subject to section 504.

We have retained the proposed definition of ''Federal financial assistance.''

Foster Care

Comment: Commenters asked us to include the phrase ''either directly or through contracts, agreements, or other arrangements with another agency or entity'' to describe the covered recipients of Federal financial assistance who provide foster care.

Response: The language ''recipient of Federal financial assistance made directly or through contracts, agreements, or other arrangements'' is included in the child welfare section, § 84.60(b), to describe covered entities.

We decline to revise the definition of ''foster care.''

Individual With a Disability

The proposed rule said that an individual with a disability means a person who has a disability but the term does not include an individual who is currently engaging in the illegal use of drugs, when a recipient acts ''on the basis of such use.''

Kiosk

Discussion of this term can be found at subpart I.

Most Integrated Setting

Discussion of this term can be found in Integration (§ 84.76).

Mobile Applications

The Department did not receive comments on the definition of this term and is finalizing it without modifications.

Other Power-Driven Mobility Device

Discussion of this term can be found in Mobility Devices (§ 84.74).

Parents

Discussion of this term can be found in Child Welfare (§ 84.60).

Qualified Individual With a Disability

Comment: One group of commenters representing persons with disabilities asked that the Department clarify that paragraph (3) in the definition of qualified individual with a disability refers to both public and private recipients.

Response: That paragraph refers to childcare, preschool, elementary, secondary, or adult educational services and it encompasses both public and private entities that are recipients from HHS. The Department has revised paragraph (4) addressing postsecondary and career and technical education services to be consistent with the Department of Education regulations.

We decline to revise the definition of ''qualified individual with a disability.''

Qualified Interpreter

Comment: Some commenters requested that the Department change the definition of ''qualified interpreter'' to more closely align with the definition of qualified interpreter for individuals with limited English proficiency proposed by the Department in its recent NPRM for section 1557.[29]

Response: The Department believes that the proposed definition of qualified interpreter in this rulemaking accurately describes the requirements of a qualified interpreter for people with disabilities. Additionally, this definition is added for consistency with title II of the ADA. For the many reasons explained in the NPRM, the Department believes there is and should be consistency between the relevant provisions of section 504 and title II of the ADA. Many recipients under section 504 are also covered entities under the ADA and the Department does not wish to cause confusion or adopt different standards in those circumstances. Both recipients and individuals with disabilities benefit from establishing consistent regulations.

We acknowledge that many recipients under section 504 are also covered entities under the Department's recent final rule under section 1557. Recipients must meet their obligations under both laws. If an interpreter does not adhere to generally accepted interpreter ethics principles, including client confidentiality, as they are required to do under section 1557, such an interpreter may not be a qualified interpreter for purposes of section 504. A failure to adhere to ethics principles may compromise the interpreter's impartiality and could also prevent a recipient from providing communication that is as effective as the recipient's communication with others (who, in the medical context, are generally entitled to confidential communication). Similarly, an interpreter that does not demonstrate proficiency in communicating in, and understanding, (1) both English and any non-English languages necessary to communicate effectively with an individual with a disability, such as American Sign Language, or (2) another communication modality (such as cued-language transliterators or oral transliteration), is likely not a qualified interpreter under section 504 because they are unlikely to be able to interpret effectively and accurately, both receptively and expressively. In order to interpret effectively, as they are required to do under section 504, qualified interpreters should be able to interpret without changes, omissions, or additions and while preserving the tone, sentiment, and emotional level of the original statement. We decline to revise the definition of ''qualified interpreter.''

Section 508 Standards

Discussion of this term can be found in subpart I.

Service Animal

Discussion of this term can be found at Service animals (§ 84.73).

State

The definition of ''State'' has been revised to more closely track the definitions section of the Rehabilitation Act, 29 U.S.C. 705(34). This is a not a substantive change.

WCAG 2.1

Discussion of this term can be found at subpart I.

User Agent

The Department has added a definition for ''user agent.'' The definition exactly matches the definition of user agent in WCAG 2.1.[30] WCAG 2.1 includes an accompanying illustration, which clarifies that the definition of user agent means ''[w]eb browsers, media players, plug-ins, and other programs—including assistive technologies—that help in retrieving, rendering, and interacting [w]eb content.'' [31]

The Department added this definition to the final rule to ensure clarity of the term ''user agent'' now that the term appears in the definition of ''web

[28] *See, e.g., U.S.* v. *Baylor Univ. Med. Ctr.,* 736 F.2d 1039, 1042 (5th Cir. 1984) (holding that ''Medicare and Medicaid are federal financial assistance for the purpose of Section 504''), cert. denied, 469 U.S. 1189 (1985).

[29] 87 FR 47824 (Aug. 4, 2022).

[30] *See* W3C, *Web Content Accessibility Guidelines 2.1* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F*. Copyright © 2023 W3C®. As discussed below, WCAG 2.1 was updated in 2023, but this rule requires conformance to the 2018 version. The Permalink used for WCAG 2.1 throughout this rule shows the 2018 version of WCAG 2.1 as it appeared on W3C's website at the time the NPRM was published.

[31] *Id.*

content.'' As discussed further at subpart I, the Department has more closely aligned the definition of ''web content'' in the final rule with the definition in WCAG 2.1. Because this change introduced the term ''user agent'' into the Department's section 504 regulation for recipients of Federal financial assistance, and the Department does not believe this is a commonly understood term, the Department has added the definition of ''user agent'' provided in WCAG 2.1 to the final rule.

Additional discussion of this term can be found at subpart I.

Web Content

Discussion of this term can be found at subpart I. The Department is editing this definition to more closely align with the definition included in WCAG 2.1.

Wheelchair

Discussion of this term can be found in Mobility Devices (§ 84.74).

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing this section with six changes. First, we are revising the definition of ''archived web content''; second, we are revising the definition of ''conventional electronic documents''; third, we are revising the term ''most integrated setting''; fourth we are adding a definition of ''Section 508 Standards''; fifth, we are adding a definition of ''user agent''; and sixth, we are revising the definition of ''web content.''

Subpart B—Employment Practices

This subpart addresses the section 504 requirements in the area of employment.

Discrimination Prohibited (§ 84.16)

Proposed § 84.16(a) prohibited discrimination on the basis of disability in employment under any program or activity receiving Federal financial assistance from the Department.

Proposed § 84.16(b) stated that the standards used to determine whether there has been discrimination in this context shall be the standards applied under title I of the ADA as they relate to employment, and, as such sections relate to employment, the provisions of sections 501 through 504 and 511 of the ADA as implemented in the EEOC's regulation at 29 CFR part 1630.

The comments and our responses regarding subpart B are set forth below.

Comment: Many organizations representing individuals with disabilities supported clarifying employment obligations and aligning the employment section of the rule with title I of the ADA. They noted that individuals with disabilities are more likely than individuals without disabilities to work in low paying jobs. Several commenters said that workforces should include individuals with disabilities in health care facilities, schools, and social work agencies to help parents and caregivers navigate the systems. They stated that a robust and disability aware workforce is needed to realize an equitable and nondiscriminatory health care system. Several individuals described their personal experiences of discrimination in the workplace.

Response: The Department appreciates the commenters' feedback on the prohibitions against discrimination in employment and of the requirement that the employment standards be aligned with title I of the ADA. We agree that it is important for workforces to include individuals with disabilities.

The Department notes that individuals who have experienced discrimination in the workplace may file complaints with OCR, though certain cases of employment discrimination may not be within OCR's statutory jurisdiction and may result in a case referral to the appropriate agency. As such, any person who believes they or another party has been discriminated against on the basis of race, color, national origin, sex, age, or disability, can visit the OCR complaint portal to file a complaint online at *ocrportal.hhs.gov/ocr/smartscreen/main.jsf.* We also accept complaints by email at *OCRcomplaint@hhs.gov* and by mail at Centralized Case Management Operations, U.S. Department of Health and Human Services, 200 Independence Avenue SW, Room 509F, HHS Building, Washington, DC 20201.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.16 as proposed with no modifications.

Subpart C—Program Accessibility

Subpart C addresses program accessibility. It provides standards for new construction and alterations and applies the concept of program access for programs or activities carried out in new as well as previously existing facilities, even when those facilities are not directly controlled by the recipient.

Discrimination Prohibited (§ 84.21)

Section 84.21 proposed to require that, except as provided in § 84.22, no qualified individual with a disability shall, because a recipient's facilities are inaccessible to or unusable by individuals with disabilities, be excluded from participation in, or be denied the benefits of the programs or activities of a recipient, or be subjected to discrimination by any recipient.

Existing Facilities (§ 84.22)

Section 84.22 currently provides that a recipient shall operate its program or activity so that when viewed in its entirety, it is readily accessible to individuals with disabilities, but does not require a recipient to make each of its existing facilities accessible to and usable by individuals with disabilities. Access to a program may be achieved by a number of means, including reassignment of services to already accessible facilities, redesign of equipment, delivery of services at alternate accessible sites, and structural changes.

We proposed in § 84.22(a)(2) to include language from the ADA title II regulation and from the section 504 regulations for federally conducted programs. It provides that, in meeting the program accessibility requirement, a recipient is not required to take any action that would result in a fundamental alteration in the program or activity or in undue financial and administrative burdens. The provision further states that the decision that compliance would result in such alterations or burdens must be made by the head of the recipient or their designee and must be accompanied by a written statement of the reasons for reaching that conclusion. The provision also states that if an action would result in such an alteration or such burdens, the recipient shall take any other action that would not result in such an alteration or such burdens but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient. We proposed to retain § 84.22(c). It provides that if a recipient with fewer than fifteen employees that provides health, welfare, or other social services finds, after consulting with a persons with a disability who is seeking services, that there is no method of providing physical access to its facilities other than making a significant alteration to its existing facilities, the recipient may, as an alternative, refer the person with a disability to other providers of the services that the person seeks that are accessible.

New Construction and Alterations (§ 84.23)

Section 84.23(a) currently requires each facility (or part of a facility)

constructed by, on behalf of, or for the use of a recipient, when such construction was begun after June 3, 1977, to be designed and constructed in such a manner that the facility (or part of a facility) is readily accessible to and usable by individuals with disabilities.

Section 84.23(b) similarly currently requires that alterations to a recipient's facility after June 3, 1977, that affect or could affect the usability of the facility or part of the facility, shall, to the maximum extent feasible, be altered in such a manner that the altered portion is readily accessible and usable by individuals with disabilities.

In the NPRM, § 84.23(c) proposed language that lays out accessibility standards and compliance dates for recipients that are public entities. Section 84.23(d) lays out accessibility standards and compliance dates for recipients that are private entities. The Department's proposal seeks to use the Standards currently used in the ADA: the 2010 ADA Standards for Accessible Design (2010 Standards).

Section 84.23(c) and (d) proposed to provide a series of compliance dates for all physical construction or alterations. Under this proposal:

If construction commences on or after one year from the publication date of the final rule, the construction must comply with the 2010 Standards.

If construction commences on or after the effective date of the rule, but before one year from the publication date of the final rule, the construction must comply either with the Uniform Federal Accessibility Standards (UFAS) or the 2010 Standards.

If construction commences on or after January 18, 1991, but before the effective date of the final rule, the construction will be deemed to be in compliance if it meets UFAS.

If construction commences after June 3, 1977, but before January 18, 1991, then the construction will be deemed to be in compliance if it meets ANSI, the American National Standard Institute's Specifications for Making Buildings and Facilities Accessible to, and Usable by, the Physically Handicapped (ANSI A117.1–1961 (R1971)).

In § 84.23(e), we proposed to provide that newly constructed or altered facilities that do not comply with the section 504 accessibility standards that were in place at the time of construction shall be made accessible in accordance with the 2010 Standards. In addition, if the construction occurred on or after January 18, 1991, and before the date one year from publication date of this rule in final form the recipient has the option of using UFAS or the 2010 Standards as the accessibility standard.

In § 84.22(g) of the NPRM, we proposed to follow the lead established by DOJ in its ADA regulations and establish a safe harbor for specific building elements. It clarifies that, if a recipient in the past had constructed or altered an element in accordance with the specifications of the accessibility code in effect at the time of construction by HHS's section 504 rule (*e.g.,* the specifications of UFAS or ANSI), such recipient is not required to retrofit that element to reflect incremental changes in this rule's accessibility standards. In these circumstances, the recipient would be entitled to a safe harbor for the already compliant elements until those elements are altered.

The comments and our responses regarding subpart C are set forth below.

Comments: Commenters were supportive of the Department's proposal to retain the basic construct of its existing section 504 rule, including strict compliance standards for new construction and alterations and a program accessibility approach for programs carried out in existing facilities. Many commenters, particularly individuals with disabilities, expressed dismay that physical barriers continue to exist so many years after the enactment of section 504, pointed out how these barriers limit or deny access to health care, and strongly urged the Department to take effective and vigorous action to enforce the regulations that are being developed. Other commenters raised concerns about specific issues in the Department's individual regulatory sections and suggested alternative text and interpretations.

Response: The Department thanks those individuals who took the time to share their experiences and concerns with the Department. These comments provided support for the Department's decision to address problems that persons with disabilities face in getting access to health care and human services, particularly with respect to medical treatment, accessible medical equipment, participation in child welfare programs, and access to websites and kiosks. The Department remains committed to maintaining its active enforcement program and notes that persons who believe that they have been discriminated against in the receipt of health care and social services may choose to file complaints with the Department and the Department will review and investigate complaints and work to achieve compliance with section 504 in those instances where the investigation reveals that discrimination has occurred. The Department will respond to the additional points raised by commenters in the individual sections that follow.

Scope of Accessibility

Comments: Several commenters expressed concern that the Department's approach to program accessibility did not address a range of other important access concerns. One commenter noted that access was more than just building and that persons with environmental illness and other invisible disabilities are denied access because of barriers created by gases from carpeting and the use of air fresheners in buildings. Another commenter included in its list of barriers that the Department should be addressing the use of inaccessible shuttle services offered by or for hospitals and operational concerns, such as storage of items on wheelchair ramps, blocked doorways, or the use of narrow or constricting rope lines.

Response: The Department notes that subpart C on Program Accessibility is just one section 504 requirement and other provisions in the rule address other aspects of accessibility. For example, the list of general prohibitions against discrimination found at §§ 84.68, particularly § 84.68(b)(7) on reasonable modifications, and 84.70 on maintenance of accessible features, address the accessibility concerns raised by these commenters.

Program Accessibility

Comments: Disability rights organizations expressed concern with the Department's continued use of the program accessibility concept for existing facilities. One organization recommended deletion of the approach because of changes in the health care industry, *i.e.,* the propensity for horizontal and vertical consolidation where hospitals merge, acquire smaller provider practices and specialty clinics, and are in turn acquired by larger regional and nation health care entities. The comment asserts that allowing accessible features in only some of these facilities under the guise of overall program access will deny persons with disabilities patient choice, care continuity, and stakeholder consultation. Other commenters, including organizations representing doctors and health care providers, expressed support for the use of program accessibility and the flexibility that it provides to small providers and approved of the Department's inclusion of the use of the defenses of fundamental alteration and undue financial and administrative burdens.

Others recommended that the Department maintain a high standard for these defenses, allowing persons

with disabilities the opportunity to participate in and benefit from health care services and programs. They also suggested that the rule should include a prompt time frame for the decision by a recipient of the use of these defenses so that an individual is not delayed access because they must wait for a written decision. Another disability rights organization expressed concern that the expanded use of telemedicine, while necessary and important, should not replace regular in-person visits in lieu of making the recipient's facilities accessible.

Response: The program accessibility requirement has been a significant feature of the Department's section 504 regulation since 1977 and is, in fact, a part of other Federal section 504 regulations, both for federally assisted and federally conducted rules.[32] The Department notes that the program accessibility requirement is derived from the language of section 504 itself, which prohibits discrimination under any ''program or activity.'' The Department's regulation here is also consistent with guidance from DOJ under E.O. 12250. DOJ's section 504 coordination regulation, which sets forth guidelines for Federal agencies to follow in issuing section 504 rules, includes language on program accessibility.[33] That provision serves as a foundation for the Department's section on program accessibility. Accordingly, the Department will continue with the concept of program accessibility as the basis for its treatment of how section 504 applies to existing facilities in its final rule. The Department notes, however, that it will continue to interpret the program accessibility concept broadly, ensuring that persons with disabilities have access to appropriate health care offered by recipients.

Section 84.22(a)(2) of the Department's proposed rule states that, in meeting the program accessibility requirement, a recipient is not required to take any action that would result in a fundamental alteration in the nature of its program or activity or in undue financial and administrative burdens. This paragraph does not establish an absolute defense; it does not relieve a recipient of all obligations to individuals with disabilities. Although a recipient is not required to take actions that would result in a fundamental alteration in the nature of a program or activity or in undue financial and administrative burdens, it nevertheless must take any other steps necessary to ensure that individuals with disabilities receive the benefits or services it provides.

It is the Department's view that this paragraph already sets a high bar and that compliance would in most cases not result in undue financial and administrative burdens for a recipient. In determining whether financial and administrative burdens are undue, all recipient resources available for use in the funding and operation of the program or activity should be considered. The burden of proving that compliance would fundamentally alter the nature of a program or activity or would result in undue financial and administrative burdens rests with the recipient. The decision that compliance would result in such alteration or burdens must be made by the head of the recipient or their designee and must be accompanied by a written statement of the reasons for reaching that conclusion. The Department recognizes the difficulty of identifying the official responsible for this determination, given the variety of organizational forms that may be taken by recipients and their components. The intention of this paragraph is to require this determination to be made by a high level official, no lower than a Department head, having budgetary authority and responsibility for making spending decisions. The Department recognizes that its regulatory language does not contain any language about the timing of the decision that an action is a fundamental alteration or would cause an undue burden. Given the wide range of sizes and types of the Department's recipients, the Department believes that setting any specific timetable would be inappropriate. Of course, any person who believes that they or any specific class of persons has been injured by the recipient's decision or failure to make a decision may file a complaint under the compliance procedures established by § 84.98 of this part, which incorporates procedural provisions applicable to the Department's title VI of the Civil Rights Act of 1964 regulations.

As to the comment concerning telehealth, the Department notes its discussion on this subject below at subpart H, Communications. The use of telehealth is an important advance in the provision of health care, but it is not the appropriate response for all situations and an in-office visit remains an important tool in the recipient's arsenal of health care solutions. Thus, telehealth in and of itself is not a solution to the existence of a health care provider's inaccessible facilities.

Small Providers (§ 84.22(c))

Comments: The Department received numerous comments on this paragraph. Disability rights organizations expressed concern about the Department's continued inclusion of a provision allowing a recipient with fewer than fifteen employees to refer a patient to alternative providers when the recipient finds, after consultation with a person with a disability seeking its services, that there is no method of complying with the program accessibility requirement other than making a significant alteration in its existing facilities. Some commenters suggested that this provision be deleted. Other commenters stated that if a recipient must use an alternative to making its services accessible, the recipient must take all steps necessary to provide the services in the most integrated setting, and give due consideration to the individual's preference after an individualized assessment of the person's needs, and provide accessible transportation at no cost to the patient. Organizations representing health care providers expressed support for the alternative referral provision, noting that it helps avoid circumstances in which complying with the rule's requirements would present an insurmountable burden for small practices and negatively impact a practice's resources for delivering care to all patients.

Response: The Department is retaining this provision in the final rule. It is necessary to keep this provision in the final rule because it implements section 504(c) of the Rehabilitation Act. Section 504(c), which Congress added to the statute in 1988, states that ''[s]mall providers'' ''are not required by [section 504(a)] to make significant structural alterations to their existing facilities for the purpose of assuring program accessibility'' where ''alternative means of providing the services are available.'' [34] The Department believes that this provision provides flexibility for the many very small providers that the Department funds. One comment suggested reducing the scope of the alternative referral to a smaller number of employees, perhaps five or fewer employees. The Department considered this proposal, but believes that changing this number here, when the fifteen or fewer number has been consistently used by the Department for its section 504 regulation since its inception, would likely cause confusion. In

[32] *See, e.g.,* 34 CFR 104.21 and 104.22 (Education); 24 CFR 8.20, 8.21, and 8.2 (HUD); 29 CFR 32.26 and 32.27 (Labor).

[33] Pursuant to E.O. 12250, DOJ coordinates implementation of section 504. 28 CFR part 41. The program accessibility requirements can be found at 28 CFR 41.56 and 41.57.

[34] 29 U.S.C. 794(c).

addition, the Department notes that, in fact, a significant percentage of the firms providing health care services (which includes doctors, dentists, and other health care providers) have fewer than five employees (52%) and an additional 20.4% have between five and nine employees.[35] The Department also notes that the consequences feared by organizations representing persons with disabilities, *i.e.,* that doctors' offices in large numbers would use this alternative referral provision to avoid making their offices accessible, has not been historically proven true, even though this provision has been in the Department's regulation since 1977.

Accessibility Standard

Comments: Comments from organizations representing persons with disabilities and a leader in the field of accessibility standards strongly recommended not using the ADA Accessibility Standards as the accessibility design standards in the final rule. They noted that the 2010 ADA Standards for Accessible Design is based on the U.S. Access Board's (Access Board) 2004 Accessibility Guidelines and is already out-of-date. They propose using the most current standard that exists because the standard in the Department's rule will likely apply into future decades. These groups recommend the use of the International Building Code (IBC) 2021 Chapter 11 and the International Code Council (ICC)/ANSI A117.1 in its entirety. They expressed the view that this approach will provide greater overall accessibility for people with disabilities and a higher level of buildings and facilities accessibility than the 2010 Standards. They also state that ICC/ANSI's A117.1 standards are the most current standards, have been developed by the private sector, and are already in use by many State and local jurisdictions. They state that these standards provide greater overall accessibility to people with disabilities and that the Department's proposed standards are based on knowledge and anthropometrics from 19 years ago (when the wheelchairs in use were smaller than those often used today). In addition, many individual commenters related stories of difficulties in accessing accessible health care and suggested that whatever standards that the Department is using should address a wide range of concerns (*e.g.,* having an accessible front entrance to a health care facility, or locating accessible room in hospitals close to nursing stations and making their use convenient for the nursing staff).

Response: While there are definite advantages to updating the accessibility design standards in the final section 504 rule to the most current standards, the Department believes that having different standards for building accessibility for the ADA and section 504 would create confusion and uncertainty for our recipients, most of whom would be then subjected to two different standards for making their facilities accessible. The Department is also aware that not all jurisdictions in the United States have adopted the ICC/ANSI 117.1 requirements and adopting them in this rule would have significant cost implications for those recipients in jurisdictions that have not yet adopted the new ICC/ANSI standards. Further, the Department is aware that the IBC is in the process of an even further update of these standards that will address an important building block issue, the use of a wider turning radius for larger wheelchairs.

Most importantly, however, the Federal Government already has in place a process for updating its accessibility standards and the Department believes that it should follow the existing procedure in place. That process includes review of accessibility guidelines by the Access Board, the agency in the Federal executive branch with the necessary architectural expertise to determine the appropriate accessibility guidelines, after conferring with all necessary stakeholders through its own notice-and-comment process. Once the Access Board updates its accessibility guidelines, Federal agencies that enforce the ADA and section 504 (and other Federal laws requiring accessible facilities) can move forward to adopt new, updated accessibility standards, for both their federally assisted and federally conducted programs. This process ensures that the Federal Government will speak with one voice on the issue of accessible building design.

The Department recognizes that its standards development process can be a lengthy one and that the Federal process is slower and less dynamic than the process followed by the private sector. The private code process allows State and local jurisdictions to determine when, whether, and in what detail they will adopt the IBC's most current standards. Under the ADA and section 504, the Federal Government requires the development of its standards through its notice-and-comment process, a process that allows a full consideration of the issue of costs and the needs for the latest approaches in accessible design.

Accordingly, the Department will retain its use of the 2010 ADA Standards for Accessible Design in its final section 504 rule. The Department, as a member of the Access Board, will bring these concerns to the full Board and will work toward an update of the Board's Accessibility Guidelines.

Subpart D—Childcare, Preschool, Elementary and Secondary, and Adult Education

Subpart D addresses requirements for childcare, preschool, elementary and secondary, and adult education. It retains with slight revisions the application section and the section dealing specifically with those types of recipients. Other sections dealing with elementary and secondary education are reserved.

Application of This Subpart (§ 84.31)

Section 84.31 of the NPRM proposed to require the subpart to apply to childcare, preschool, elementary and secondary, and adult education programs or activities that receive direct or indirect Federal financial assistance and to recipients that operate, or that receive Federal financial assistance for the operation of, such programs or activities. The Department notes that childcare vouchers or certificates are considered indirect Federal financial assistance and, for the purposes of applying the Child Care and Development Block Grant (CCDBG) regulations, are assistance to the parent. Section 504 applies to both direct and indirect Federal financial assistance, including vouchers. This subpart reaffirms that section 504 applies to child care providers, but it does not change the conditions that apply to recipients of indirect Federal financial assistance under any other statute, such as the statute establishing the CCDBG program. For example, faith-based child care providers that receive vouchers or certificates through the Child Care and Development Fund (CCDF) are not barred by that statute from providing religious programming and materials, though section 504 applies to them. OCR will work with the Administration for Children and Families to provide additional guidance and implementation assistance to child care providers receiving Federal financial assistance.

[35] U.S. Census Bureau, Stat. of U.S. Bus. (2019), *https://www.census.gov/programssurveys/susb.html.*

Childcare, Preschool, Elementary and Secondary, and Adult Education (§ 84.38)

Section 84.38 proposed to prohibit these types of recipients, on the basis of disability, from excluding qualified individuals with disabilities and requires recipients to consider the needs of such persons in determining the aids, benefits, or services to be provided.

The comments and our responses regarding subpart D are set forth below.

Comment: Several commenters expressed support for the inclusion of the term ''childcare'' in the new regulation, which uses currently accepted terms and reduces unintended stigma related to references to parents and children with disabilities by removing outdated phrases such as ''handicapped.''

Response: The Department appreciates commenters' support and believes using current terms plays an important role in inclusive and accessible childcare programs.

Comment: Several commenters requested clarification that the age range covered under § 84.38 of subpart D begins at birth and recommended this be made explicit in the final regulation.

Response: The Department appreciates this comment. A ''qualified individual,'' as defined under section 504, can be of any age, including from birth. Therefore, the Department declines to add further text in the regulation.

Comment: Many commenters emphasized that childcare providers are currently unaware of their obligations under section 504 and the ADA. Commenters requested additional guidance from OCR and the Administration for Children and Families (ACF) in how these providers can meet their obligations, including assurance of availability of supports, training opportunities, and resources including in plain language and multiple languages. Additionally, some commenters asked for guidance on how this rule should be read in concert with the Department of Education's (ED's) section 504 rule in educational settings. Lastly, commenters asked for clarification on how disciplinary policies and practices will be applied in a nondiscriminatory manner.

Response: The Department collaborates closely with our Federal partners on section 504, including DOJ and ED. In collaboration with ED, HHS recently updated a joint Policy Statement on Inclusion of Children with Disabilities in Early Childhood Programs, which discusses the legal foundation for inclusion and opportunities to improve inclusion in early childhood programs.[36] As explained in the NPRM, the Department believes there is and should be consistency between the relevant provisions of section 504 and title II of the ADA and its regulation [37] as well as ED's section 504 regulations.[38] We encourage recipients to consult DOJ's guidance titled ''Commonly Asked Questions About Child Care Centers and the Americans with Disabilities Act,'' first issued in 1997 and updated in 2020, that describes providers' obligations under title III.[39] In addition to consistency in the relevant provisions, title II of the ADA and section 504 generally are interpreted consistently, as detailed in the NPRM.

Recipients should also be aware of the wealth of materials available free of charge from the HHS-funded ADA National Network at *www.adata.org,* including specific information about the provision of childcare services.[40] DOJ also provides guidance and resources at *www.ada.gov.*

HHS in coordination with ED, will work with childcare providers to provide guidance and technical assistance on implementation. Both Departments understand that providers will need information and technical assistance to understand their obligations to individuals with disabilities.

Comment: Several commenters expressed concern over discrimination in childcare settings and asked that OCR provide additional guidance regarding the criteria used to determine whether a modification is a ''fundamental alteration'' to a program or activity or an ''undue financial and administrative burden'' for the purpose of responsibilities under section 504. For example, several commenters stated that modification requests for children with diabetes in childcare settings frequently result in denial or exclusion. Commenters asked for a non-exhaustive list of diabetes-related examples of what reasonable modifications in childcare settings may include.

Response: We appreciate the commenters' request for additional guidance on reasonable modifications. As throughout this regulation, which modifications are reasonable and necessary to avoid discrimination depends on the specific circumstances. Examples of common reasonable modifications for a child with diabetes may include providing or assisting with blood glucose checks, insulin administration, counting carbohydrates, and taking action in response to low and high blood glucose levels. DOJ's guidance titled ''Commonly Asked Questions About Child Care Centers and the Americans with Disabilities Act,'' provides relevant examples of reasonable modifications under the ADA which also apply under section 504, such as the use of service animals, assistance with diapering and toileting, and assistance with orthotic devices.[41] These scenarios are illustrative examples of what reasonable modifications a covered entity may be required to make to ensure a child with a disability can participate in its programs. The Department will note the request for more examples of reasonable modifications in our continuing education and technical assistance efforts, including the issuance of possible further guidance.

Summary of Regulatory Changes

In light of the discussion above and considering the comments received, we are finalizing subpart D as proposed with no modifications.

Subpart E—Postsecondary Education

Subpart E addresses postsecondary education. The Department funds many health-related schools that are covered by this part including schools of medicine, dentistry, and nursing. This subpart is identical to the postsecondary education provisions in the existing section 504 regulations and in the ED regulations at 34 CFR 104.41 through 104.47. This subpart contains the following sections: Application, Admissions and Recruitment, Treatment of Students, Academic Adjustments, Housing, Financial and Employment Assistance to Students, and Nonacademic Services.

[36] U.S. Dep't of Health & Human Servs., U.S. Dep't of Ed., Policy Statement on Inclusion of Children with Disabilities in Early Childhood Programs (updated November 2023). The guidance notes that '' 'early childhood programs' refer to those that provide early care and education to children birth through age five, including but not limited to childcare centers, family childcare, Early Head Start, Head Start, home visiting programs, and public and private pre-kindergarten in-school and community-based settings.'' *Id.* at 1.

[37] *See* 28 CFR part 35.

[38] *See* 45 CFR 84.4(b)(2) and 34 CFR 104.4(b)(2).

[39] U.S. Dep't of Justice, Commonly Asked Questions About Childcare Centers and the Americans with Disabilities Act (2020), *https://www.ada.gov/childqanda.htm.*

[40] The ADA National Network receives funding from HHS to provide information, guidance and training on how to implement the Americans with Disabilities Act (ADA).

[41] U.S. Dep't of Justice, Commonly Asked Questions About Childcare Centers and the Americans with Disabilities Act (2020), *https://www.ada.gov/childqanda.htm; and see* U.S. Dep't of Educ., Section 504 Protections for Students with Diabetes (2024), *https://www2.ed.gov/about/offices/list/ocr/docs/ocr-factsheet-diabetes-202402.pdf.*

The comments and our responses regarding subpart E are set forth below.

Comment: Many commenters, including disability rights organizations, said that access to postsecondary education, adult education, and technical programs is critical for diversifying the medical field. Several stated that disability should be included in the curricula of all medical, nursing, and other health care professional schools. One commenter urged HHS to take any actions that it can to combat discrimination against individuals with disabilities at every level of education, especially with regard to students and practitioners in the fields of biomedical and behavioral research, medicine, and allied health and human services. They asserted that this is one of the most effective steps that can be taken to eradicate a leading cause of the most egregious and endemic forms of disability-based discrimination in the U.S. today.

Several other individuals similarly complained about the difficulty in obtaining modifications and urged that the burden be alleviated. One commenter said that recipients consistently require more than just a clinical diagnosis of disability. He noted that obtaining other documents is sometimes very difficult, especially for individuals who live in rural areas.

Response: We thank commenters for their feedback. We agree with those who commented on the importance of providing individuals with disabilities equal access to educational programs and activities. We also agree that disability should be addressed in the curricula of postsecondary education programs. The Department currently has a Medical School Curriculum Initiative in partnership with the Association of American Medical Colleges.[42]

In addition, the Department has authority to enforce the provisions in subpart E which ensure that individuals receive equal access to postsecondary educational programs. We are committed to vigorous enforcement of those regulations. The Department notes that it proposes in this final rule to promulgate § 84.68(b)(7), which will be particularly important for educational institutions as it will require the provision of reasonable modifications to policies, practices, and procedures when such modifications are necessary to avoid discrimination on the basis of disability, unless the recipient can demonstrate that making the modifications would fundamentally alter the nature of the program or activity. Postsecondary educational institutions must also comply with requirements specific to them contained in § 84.44, Academic Adjustments. That section requires postsecondary educational institutions to make modifications to academic requirements if necessary to ensure nondiscrimination on the basis of disability. Modifications may include changes in the length of time permitted for completion of degree requirements, substitution of specific courses required for the completion of degree requirements, and adaptation of the manner in which specific courses are conducted.

In response to the concern that recipients consistently require more than just a clinical diagnosis of disability, we note that § 84.4(d)(1)(vii) says that determining whether an impairment substantially limits a major life activity usually will require no scientific, medical, or statistical evidence. The preamble to that provision in the ADA title II regulations states that ''in most cases, presentation of such evidence shall not be necessary.'' [43] Individuals who believe they have been unfairly denied reasonable modifications and/or academic adjustments can file complaints with OCR. The procedures for filing complaints are explained in § 84.98.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing subpart E as proposed with no modifications.

Subpart F—Health, Welfare, and Social Services

This subpart sets forth the requirements that apply to health, welfare, and social service providers.

Substance and Alcohol Use Disorders (§ 84.53)

Proposed § 84.53 retained the section of the existing regulation with non-substantive terminology updates. The proposed version stated that a recipient to which this subpart applies that operates a general hospital or outpatient facility may not discriminate in admission or treatment against an individual with a substance or alcohol use disorder or individual with an alcohol use disorder who is suffering from a medical condition, because of the person's drug or alcohol use disorder.

We invited comment as to whether the application of this section should extend beyond hospitals (including inpatient, long-term hospitals, and psychiatric hospitals) and outpatient facilities. If so, what types of treatment programs, providers, or other facilities should be included in this section?

The comments and our responses regarding § 84.53 are set forth below.

Comment: Multiple commenters, including many disability rights organizations, responded to our request for comment. The commenters were uniformly supportive of the extension of coverage of this section beyond hospitals and outpatient facilities. A few listed specific health care facilities that should be included but most said that coverage should be extended to ''all health care facilities.''

Several commenters questioned how the prohibitions in § 84.53 are different from the prohibitions against discrimination in the medical treatment section, § 84.56. Another commenter was not clear as to why we said that this section must be read in conjunction with the illegal drugs provision at § 84.69(b). A few commenters pointed out a technical error in the text of the proposed rule where insertion of the phrase ''or individual with an alcohol or substance use disorder'' makes the sentence confusing.

Response: We thank commenters for their feedback and agree with their unanimous recommendation that we expand the application of the section to all health care providers.

There are many settings where individuals seek and receive care other than hospitals and outpatient facilities. These include rehabilitation centers, assisted living and residential care facilities, day treatment programs, home health care services, telehealth platforms, and specialty clinics. The current opioid crisis and increase in substance use disorders underscores the necessity for nondiscriminatory access to a wide range of health care facilities.

The Department believes that health care treatment should be as inclusive as possible and should not be limited to hospitals and outpatient facilities. Any health care facility receiving Federal financial assistance from the Department may not discriminate in admission or treatment against an individual with an alcohol or substance use disorder who has a medical condition because of that alcohol or substance use disorder. In response to a commenter's question about how this section is different than the nondiscrimination provisions in the

[42] For more information on this initiative, *see* U.S. Dep't of Health & Human Servs, Off. for Civil Rts, Medical School Curriculum Initiative in partnership with the Association of American Medical Colleges, *https://www.hhs.gov/civil-rights/for-individuals/special-topics/health-disparities/medical-school-curriculum-initiative/index.html.*

[43] 35 CFR part 84, appendix C.

medical treatment section, we note that this section provides specific protections for individuals with substance and alcohol use disorders but that the general prohibitions against discrimination contained in the medical treatment section at § 84.56 also apply to that situation.

With regard to the relationship of this section to the provisions about illegal use of drugs contained in § 84.69, we note that § 84.69(a) states that ''[e]xcept as provided in paragraph (b) of this section, this part does not prohibit discrimination against individuals based on their current illegal use of drugs.'' The exception in paragraph (b) states that ''a recipient shall not exclude an individual on the basis of that individual's illegal use of drugs from the benefits of programs and activities *providing health services*. . . .'' (emphasis added). The situation described in § 84.53 fits into that exception since it addresses individuals who are seeking health care services. Accordingly, recipients cannot deny health services on the basis of the current illegal use of drugs if the individual is otherwise entitled to such services.

We note that §§ 84.69 and 84.53 differ in two key ways. First, § 84.53 protects people with both substance use and alcohol use disorders while § 84.69 only addresses individuals engaging in illegal use of drugs. Second, § 84.69(b) prohibits exclusion of individuals currently engaging in illegal use of drugs from health services and services provided under the Rehabilitation Act while § 84.53 does not address the illegal drugs issue. However, as noted above, both regulations prohibit the exclusion of individuals currently engaging in illegal use of drugs from health services although this is not specifically stated in § 84.53.

Please see the preamble discussion to § 84.69, Illegal Use of Drugs, for an explanation of how the ADA sections and Rehabilitation Act sections on illegal drugs differ.

We agree with the commenters' suggestion that the text be clarified by deleting the phrase ''or individual with alcohol use disorder.'' In addition, we are making two technical changes—replacing the word ''drug'' with the word ''substance'' and replacing the phrase ''who is suffering from a medical condition'' to ''who has a medical condition.''

Summary of Regulatory Changes

For the reasons set forth above and considering comments received, we are finalizing § 84.53 as proposed with several modifications. We are replacing the phrase ''operates a general hospital or outpatient facility'' with the phrase ''operates a health care facility.'' In addition, we are deleting the phrase ''or individual with an alcohol use disorder'' the second time it is used, replacing the word ''drug'' with the word ''substance, and replacing the phrase ''suffering from a medical condition'' to ''has a medical condition.'' The section now says that ''[a] recipient . . . who operates a health care facility may not discriminate in admission or treatment against an individual with a substance or alcohol use disorder who has a medical condition, because of the person's substance or alcohol use disorder.''

Education of Institutionalized Persons (§ 84.54)

Proposed § 84.54 was retained from the existing section 504 regulations with one revision. The existing regulation stated that recipients must ensure that qualified individuals with disabilities are provided an appropriate education as defined in § 84.33(b). That section set forth the requirements for a free appropriate public education. However, the proposed rule did not contain a § 84.33(b) as that section had been removed. Accordingly, we proposed to revise § 84.54 so that it refers instead to the ED section 504 regulations at 34 CFR 104.33(b). The comments and our responses regarding § 84.54 are set forth below.

Comment: Several disability rights organizations expressed concerns about the reference to 34 CFR 104.33(b), ED's section 504 regulation, since that Department has indicated their intent to amend their section 504 regulations. Their comments do not explain their concern; they simply suggest that the rule not reference a regulation that will be amended. The commenters proposed alternative language setting forth requirements for an appropriate education. They also suggested that the preamble state that this section is to be interpreted consistent with the requirements of ED's section 504 regulations and the ADA title II regulations.

Response: We appreciate the commenters' suggestions but decline to revise the text of the regulation. We note that recipients must comply with the current version of 34 CFR 104.33(b). If amendments to 34 CFR 104.33(b) are finalized, in whole or in part, following the effective date of this regulation, then recipients must follow the amended version in force at that time. The cross-reference to the ED regulation does not change that requirement. We agree with recipients' assertion that recipients must comply with both the ED and the ADA title II regulations.

Summary of Regulatory Changes

For the reasons set forth above, we are finalizing § 84.54 as proposed without modifications.

Medical Treatment (§ 84.56)

Proposed § 84.56(a) proposed a general prohibition against discrimination to be read in conjunction with the general prohibitions contained in proposed § 84.68.

Proposed § 84.56(b)(1) provided a non-exhaustive list of examples of conduct that would violate the section. It stated that a recipient may not deny or limit medical treatment to a qualified individual with a disability when the denial is based on (i) bias or stereotypes; (ii) judgments that an individual will be a burden on others due to their disability; or (iii) a belief that the life of a person with a disability has lesser value than the life of a person without a disability, or that life with a disability is not worth living.

In § 84.56(b)(2), we proposed to provide that where an individual with a disability seeks or consents to treatment for a separately diagnosable symptom or medical condition, a recipient may not deny or limit clinically appropriate treatment if it would be offered to a similarly situated individual without an underlying disability.

The Department invited comment on the best way of articulating distinctions between underlying disabilities and separately diagnosable symptoms or medical conditions.

We proposed in § 84.56(b)(3) to provide that a recipient may not provide medical treatment to an individual with a disability where it would not provide the same treatment to an individual without a disability unless the disability impacts the effectiveness, or ease of administration of the treatment itself, or has a medical effect on the condition to which the treatment is directed.

The Department invited comment on other examples of the discriminatory provision of medical treatment. Proposed § 84.56(c) articulated a rule of construction setting forth a series of principles guiding how proposed § 84.56 should be interpreted. We proposed in § 84.56(c)(1)(i) to provide that nothing in this section requires the provision of medical treatment where the recipient has a legitimate, nondiscriminatory reason for denying or limiting that service or where the disability renders the individual not qualified for the treatment.

Proposed § 84.56(c)(1)(ii) identified the circumstances when a recipient typically declines to provide treatment and proposed that the criteria in paragraphs (b)(1)(i) through (iii) would not be legitimate nondiscriminatory reasons for denying or limiting medical treatment and could not be a basis for determining that an individual is not qualified for treatment or that a treatment is not clinically appropriate.

The Department invited comment on the examples described in this section, whether additional examples were needed and on the appropriate balance between prohibiting discriminatory conduct and ensuring legitimate professional judgments.

Proposed § 84.56(c)(2) addressed the role of consent in evaluating obligations under § 84.56. We proposed in § 84.56(c)(2)(i) to make clear that nothing in the section requires a recipient to provide medical treatment to an individual where the individual does not consent to the treatment. We proposed in § 84.56(c)(2)(ii) to provide that nothing in the section allows a recipient to discriminate against a qualified individual with a disability in seeking to obtain consent.

We proposed in § 84.56(c)(3) to provide that nothing in the section precludes a recipient from providing an individual with a disability with information regarding the implications of different courses of treatment based on current medical knowledge or the best available objective evidence.

The comments and our responses regarding § 84.56 are set forth below.

Comments: Commenters expressed broad support for the medical treatment section, with many expressing particular support for the general prohibition against discrimination. Many people with disabilities shared experiences regarding the inappropriate denial of medical treatment, while many provider organizations expressed appreciation for the regulatory clarity and respect for professional judgment in the proposed provision.

Response: The Department appreciates the broad support for this section. We also thank all of the commenters who took the time to share their experiences with us.

Comments: Many commenters indicated that further guidance, public education, and technical assistance activities will be necessary to promote compliance and awareness of the obligations of the new medical treatment section. Examples include issuing supporting Frequently Asked Questions, guidance for health care providers and others on the use of supported decision-making and other reasonable modifications to support accessibility and nondiscrimination, guidance on what is and is not a legitimate, nondiscriminatory reason for denying or limiting a service, expectations for documentation of legitimate nondiscriminatory reasons, guidance on how the prohibition on discrimination in medical treatment interacts with other sections of the regulation, and other topics.

Response: The Department agrees that further efforts may be necessary to promote awareness of and compliance with the medical treatment sections of this rulemaking. The Department will consider a variety of options for such activities after the issuance of the final rule, including sub-regulatory guidance and technical assistance.

Definition of Medical Treatment

Comments: Multiple commenters suggested the final rule should include a definition of medical treatment. Many suggested changes to the description of medical treatment included in the NPRM. Some commenters suggested the Department include additional types of health conditions to the description of medical treatment, specifically suggesting additions such as intellectual, developmental, or behavioral health conditions to the language ''physical and mental health conditions'' in the proposed rule. Several commenters asked the Department to clarify if habilitative services would be covered medical treatment. Other commenters requested we use a new term entirely that they believed would better encompass the breadth of treatment, like ''treatment options,'' ''health care services,'' ''comprehensive medical care,'' ''medical services,'' or ''goods, benefits, or services.'' Another commenter requested that we clarify that the term is inclusive of services delivered in the context of clinical research.

Response: The Department has elected not to define the term ''medical treatment'' in the regulation, but instead uses the term in a generic, nonspecific manner. As stated in the preamble to the proposed rule, ''medical treatment'' is intended to be broad and inclusive. The Department interprets medical treatment to encompass habilitative services and services delivered as part of clinical research. The term physical or mental health condition in the description of medical treatment in the proposed rule is sufficiently broad to encompass the additional, suggested language referenced by the commenters, including intellectual, developmental, or behavioral health conditions, etc. We will retain the approach in the proposed rule, giving ''medical treatment'' its plain meaning, and reiterating that it is intended to be broad and inclusive.

Notice

Comments: Several commenters requested that the Department require all forms of medical treatment to include a notice of requirements under section 504 to familiarize people with disabilities receiving medical treatment from recipients with recipient obligations and patient rights pursuant to them.

Response: We decline to make this change. Section 84.8, Notice, requires all recipients to make available to beneficiaries and other interested persons information about the provisions of section 504 and its applicability to the programs or activities of the recipient. Recipients must take such steps as necessary to apprise individuals of the protections against discrimination assured them by section 504 and this part, however we decline at this time to regulate how and when recipients are required to do that.

Best and Promising Practices

Comments: Several commenters recommended best practices for addressing disability discrimination, including competency-based trainings on disability; a mechanism for allowing individuals with disabilities to appeal medical treatment denials or limitations; a structured process for requesting a second opinion/professional consultation; and the availability of a specially trained, independent review board—with a composition that includes people with a wide range of disabilities—to consider patient appeals of medical treatment decisions and report publicly on the outcome of those decisions.

Response: While these ideas are potentially promising practices for assisting persons with disabilities as they seek health care, the Department believes it is unnecessary to include these requirements at this time to ensure compliance with section 504's nondiscrimination requirement. Recipients may consider them as potential options within a holistic strategy of providing health care to persons with disabilities.

Utilization Management Practices

Comment: A medical organization asked the Department to respond to an example under which ''a drug that slows the progression of visual impairment is clinically appropriate only if a patient has a minimum level of visual acuity remaining based on the enrolled populations in the drug's

clinical trials,'' leading ''a Medicare Part D plan [to] place a prior authorization requirement that the patient have that minimum level of visual acuity for the drug to be covered by the plan.'' They ask the Department whether such a prior authorization that would only cover the drug for those with the minimum level of visual acuity would be viewed as discriminatory under section 504.

Response: As indicated elsewhere within the preamble, prior authorization and other utilization management activities are covered by section 504 and § 84.56. However, determining whether a particular prior authorization or other utilization management decision by a health plan may violate section 504 is a fact-specific inquiry that we do not address in this final rule.

Interaction With Medicare

Comment: A medical organization noted their obligation under Medicare Parts A and B and Medicare Advantage to allow coverage only for items and services that are ''reasonable and necessary for the diagnosis or treatment of illness or injury or to improve the functioning of a malformed body member'' as well as their obligation under Medicare Part D to require that a drug be for a ''medically accepted indication.'' They also ask that the Department include specific regulatory language in the final rule deeming the application of coverage restrictions in Federal health programs to meet the proposed rule's standard for being nondiscriminatory and, therefore, permissible.

Response: As the Department discusses elsewhere with respect to the interaction of section 504's integration mandate and Medicaid law, obligations under civil rights laws and program statutes, such as for Medicare, are separate and distinct. Recipients are not required to fundamentally alter their programs or activities to comply with section 504. However, recipients may be obligated to make reasonable modifications to programs or services in order to comply with section 504 even if they are fully in compliance with applicable program statutes in Federal health programs. As such, the Department has elected not to modify the regulatory text.

Scope of § 84.56

Comment: One commenter requested that we make clear that the general prohibitions on discrimination in proposed § 84.68 continue to apply in the context of medical treatment notwithstanding proposed § 84.56's more specific provisions on discrimination in medical treatment.

Response: The general prohibition against discrimination in proposed § 84.68 continues to apply in the context of medical treatment. While § 84.56 articulates more specific prohibitions, this does not preclude the application of § 84.68's more general requirements to medical treatment or any of the other areas in which the Department has included more specific regulatory provisions, nor should the omission of a specific regulatory provision on a particular topic be construed to suggest that the general prohibition against discrimination does not apply in that context.

Comments: Several commenters suggested modifying § 84.56(a) to clarify that its prohibition on discrimination encompasses offering, failing to offer, or denying a treatment.

Response: The Department agrees that § 84.56(a)'s prohibition on discrimination on the basis of disability can encompass instances where a recipient offers, fails to offer, or denies a treatment. Other provisions within the rule which provide further detail on the prohibitions within § 84.56(a) explicitly indicate this, such as § 84.56(b). We believe these prohibitions are covered by the rule already, and thus decline to change the regulatory text.

Comments: Several commenters asked the Department to clarify how § 84.56 applies to payers, including Medicaid managed care plans, Medicare Advantage plans, and other health systems payers receiving Federal financial assistance.

Response: Section 84.56 applies to all medical treatment provided by recipients receiving funds from HHS. The application of § 84.56 in such instances will depend on the specific facts and institutional context of each case.

Comments: Many commenters asked the Department to specifically clarify other forms of medical treatment that § 84.56 would apply to, including assisted reproductive technology treatment, suicide prevention services, mental health services, and others.

Response: As indicated previously, the Department intends § 84.56 to apply in a broad and inclusive fashion to a wide array of medical treatment services, including assisted reproductive technology treatment, suicide prevention services, mental health services, and others. ''Medical treatment'' is used in § 84.56 in a generic, nonspecific manner; it is intended to be broad and inclusive. It refers to the management and care of a patient to identify, address, treat, or ameliorate a physical or mental health condition, injury, disorder, or symptom, whether or not the condition constitutes a disability and whether the medical approach is preventive, curative, habilitative, rehabilitative, or palliative. Although it is not possible to provide an exhaustive list of such services, recipients should interpret the term medical treatment in the broad and inclusive fashion intended by the Department.

Comments: Some commenters requested the Department clarify that § 84.56 applies both to patients with disabilities that predate the provision of medical treatment in which discrimination occurs, and patients whose prognosis during that episode of medical treatment includes disability.

Response: As discussed elsewhere in this rulemaking, the definition of disability under section 504 is intended to be interpreted in a broad and inclusive fashion. The definition of disability includes people with disabilities whose disability predates the provision of medical treatment in which discrimination occurs. As far as the question of patients whose prognosis during the episode of medical treatment includes disability, people with physical or mental impairments that substantially limit a major life activity, including a major bodily function, qualify as people with disabilities. As indicated elsewhere within the rule, ''major life activities'' includes not only activities such as caring for oneself, seeing, hearing, and walking, but also includes the operation of a major bodily function such as the functions of the immune system, normal cell growth, and reproductive systems. Where a person's prognosis is the result of impairments in a major bodily function, they would be considered a person with a disability under section 504. We note also that section 504 protects persons who are ''regarded as'' having such an impairment. In cases of illness or injury so severe that a person needs a ventilator and tube feeding, or where a person is regaining consciousness after brain injury, as raised in comments received on this issue, although it will be a fact-specific inquiry, the individuals in these scenarios would almost certainly be covered under the definition of disability and by the protections from discrimination on the basis of disability under section 504, including § 84.56.

Comments: Several commenters asked the Department to clarify the application of § 84.56 to newborn infants.

Response: As indicated within the NPRM, the Department considers

section 504, including § 84.56, to apply to newborn infants. This includes the prohibitions against the denial of medical treatment under § 84.56(b)(1) and (2), and the prohibitions on the discriminatory provision of medical treatment under § 84.56(b)(3).

Comment: One commenter objected based on its understanding that the Department's proposed rule would not apply to decisions to withhold treatment from infants with disabilities in which the disabling condition is related to the condition to be treated, noting that § 84.56(b)(2) addresses treatment for a separately diagnosable condition or symptom and not for the underlying disability. The comment concerned infants with disability conditions such as meningomyelocele, hydrocephaly, microcephaly, or other anatomical anomalies. The comment noted that failure to treat these conditions represents discrimination against a child with a disability.

Response: The Department believes that this comment misconstrues the section 504 rule. The Department intends that this rule will generally apply to the provision of medical treatment for infants, including those seeking treatment for separately diagnosable symptoms or conditions related to their underlying disability, when medical treatment is provided to other similarly situated children. For example, an infant with microcephaly may experience seizures. This would constitute a separately diagnosable symptom or condition for which treatment would be subject to the protections of § 84.56(b)(2) despite the fact that the seizures are a symptom of the infant's microcephaly. As the Department's NPRM made clear, with respect to separately diagnosable conditions, the rule will not require that the condition be entirely unrelated to the underlying disability. ''Nor does it matter for these purposes whether the condition for which the individual is seeking treatment is in some sense causally related to the underlying disability if the decision to refuse treatment would not be made as to similarly situated individuals without the disability.'' 88 FR 63405. In addition, § 84.56(b)(1) prohibits denying or limiting medical treatment to a qualified individual with a disability based on bias or stereotypes about that patient's disability, judgments that the individual will be a burden on others due to their disability, or a belief that the life of a person with a disability has a lesser value than the life of a person without a disability or that life with a disability is not worth living. Under such circumstances, the discrimination described by the commenter would also be covered under § 84.56(b)(1) even if the condition for which the patient sought treatment was not a separately diagnosable symptom or condition from their underlying disability.

Medical Futility

The Department proposed § 84.56(b)(1)(iii) to prohibit recipients from denying or limiting medical treatment based on the provider's belief that the life of a person with a disability has a lesser value than a person without a disability, or that life with a disability is not worth living.

Comments: The Department received a broad array of comments from disability organizations, civil rights organizations, and other stakeholders supporting this approach. We received stories from people with disabilities describing their own experiences or those of friends regarding the denial of life-sustaining treatment and the difficulties involved in accessing it after such denials. We also received similar stories from providers. For example, one provider association described a 25-year-old patient with a developmental disability who had been referred to an inpatient hospice unit after becoming poorly responsive with brain imaging demonstrating a shunt and severe abnormalities. After the provider learned from a family member of a recent sudden change in the patient's behavior, the patient received a second opinion, leading to the shunt being surgically revised, the patient's condition improving, and her enjoying her life for many more years. In the words of this commenter, the patient's ''referral to hospice without sufficient exploration of other treatment options was inappropriate and may have been driven by a mistaken clinical assumption regarding her baseline quality of life.''

Response: The Department will retain the provision as proposed. We respond to specific questions regarding the application of this requirement throughout this section.

Comments: Several commenters requested that the Department provide an example of the application of § 84.56(b)(1)(iii) to people with intellectual disabilities.

Response: The Department provided such an example within the NPRM. We noted an illustrative example in which a teenage boy with intellectual and developmental disabilities develops periodic treatable respiratory infections and pneumonia due to a chronic condition. Judging his quality of life to be poor due to cognitive and communication disabilities, his provider decides to withhold antibiotics and other medical care when the boy becomes ill. Instead, his provider—who is a recipient of Federal financial assistance—refers the boy to hospice care and declines to provide life-sustaining treatment. The provider makes this decision not because she anticipates that care would be ineffective, but because she determines that such care would be effective at prolonging the patient's life and that the patient's life would not be worth living on the basis of the patient's disability. Because the provider has withheld life-sustaining care based on the judgment that the patient's life as an individual with a disability is not worth living, the boy is a qualified individual who has experienced discrimination on the basis of disability in violation of § 84.56(b)(1)(iii).

Comment: A commenter asked for additional clarity regarding the permissibility of not offering treatment where doing so ''does not align with the patient's wishes, does not take into account their overall prognosis, does not consider whether the risks would outweigh the benefits, or creates a situation where the treatment could cause more harm than good.''

Response: The commenter raised multiple potential rationales for denying treatment, each of which has different legal implications under § 84.56 and section 504 more generally. As the Department indicates in § 84.56(c)(2), ''Nothing in this section requires a recipient to provide medical treatment to an individual where the individual, or their authorized representative, does not consent to that treatment.'' As such, recipients will not be required to provide treatment that does not align with a patient's expressed wishes or advanced directive.

The permissibility of denial of treatment based on other potential rationales raised by the commenter are context- and fact-dependent. We indicate in § 84.56(c)(1)(i) that nothing in this section requires the provision of medical treatment where the recipient has a legitimate, nondiscriminatory reason for denying or limiting that service or where the disability renders the individual not qualified for the treatment. Where a patient's prognosis affects whether treatment is likely to be effective, it may be permissible to consider prognosis in determining whether a treatment should be provided. Similarly, where a treatment is likely to have substantial side effects that may outweigh the likely benefits to the patient, it may be permissible to take these into account in determining whether a treatment should be provided

as these risks are relevant to whether a treatment is medically effective. However, consideration of a patient's prognosis may not include a judgment that the life of a person with a disability is not worth living or will be a burden on others due to their disability, as these are prohibited criteria under § 84.56(b)(1)(i) through (iii). In short, while recipients may take into account potential harms to the patient, those harms may not include or be based on a belief that the patient would be better off dead than alive due to their disability.

Comments: In the NPRM, the Department provided an example involving a patient with Alzheimer's disease, covered as a disability under section 504, who has developed pneumonia and needs a ventilator to provide assistance breathing. His husband has requested that physicians start the patient on a ventilator, consistent with what the patient's husband believes would be his spouse's wishes. The attending physician, who is a recipient of Federal financial assistance from HHS and works in a hospital that is also a recipient, tells the patient and his husband that the patient should not receive a ventilator, given the poor quality of life the physician believes the patient experiences because the latter has Alzheimer's disease. This situation occurs even though the attending physician normally would start ventilator support for a patient with pneumonia who needs assistance breathing. The physician believes that the patient's Alzheimer's disease renders the continuation of the patient's life to have no benefit, and therefore the physician declines to put the patient on the ventilator. We indicated that under these circumstances the physician has denied life-sustaining care for the patient based on judgments that the patient's quality of life renders continued life with a disability not worth living and has failed to provide care that he would have provided to an individual without a disability. In denying access to ventilator support, the doctor has violated § 84.56(b)(1)(iii).

We received multiple comments specific to this example. Most commenters, particularly those representing aging and disability advocacy organizations, praised its inclusion, noting that it addressed an important issue facing both people with Alzheimer's and those with other cognitive disabilities, and requesting that it be incorporated within the final rule. A minority of commenters expressed concern with the use of Alzheimer's disease and suggested the Department consider the use of another diagnosis or specify that only ''early and mild'' Alzheimer's is covered in the circumstances described by the illustrative example.

Response: The example describes the denial of medical treatment due to the provider's belief that the patient has such poor quality of life due to their disability that life-sustaining treatment would not be of benefit to them. This is a denial of treatment based on a belief that life with the patient's disability is not worth living, a prohibited basis for a denial of medical treatment under § 84.56(b)(1)(iii) and not a legitimate nondiscriminatory reason to deny treatment, as specified under § 84.56(c)(1)(ii). The example also indicates that this occurs even though the attending physician normally would start ventilator support for a patient with pneumonia who needs assistance breathing. We note that if the physician reasonably determines based on current medical knowledge or the best available objective evidence that such medical treatment is not clinically appropriate for the patient due to their Alzheimer's disease, this would not constitute prohibited discrimination. However, such a determination cannot—consistent with § 84.56(c)(1)(ii)—be based on a judgment that the patient's life is not worth living due to their Alzheimer's disease.

We note that the prohibition against denying treatment due to a judgment that the patient's quality of life would be so low as to make their life not worth living does not mean that a physician cannot communicate this concern to the patient or their authorized representative to inform their decision-making, provided the physician does not discriminate on the basis of disability in the manner in which they seek permission to withdraw or encourage the declining of life-sustaining treatment (such as through pressuring the patient or their representative). This was why we specified in this example that the patient's authorized representative had sought medical treatment for the patient with Alzheimer's disease and that this treatment would have been provided to a similarly situated person without Alzheimer's disease.

Comment: Organizations representing older adults and people with disabilities asked the Department to interpret the permissible application of medical futility narrowly and indicated that recipients must explicitly take into account disability accommodations when making determinations of medical futility. They also ask the Department to include examples of the consideration of reasonable modifications when making decisions regarding medical futility.

Response: In the NPRM, the Department noted a 2015 policy statement from the American Thoracic Society, the American Association for Critical Care Nurses, the American College of Chest Physicians, the European Society for Intensive Care Medicine, and the Society of Critical Care Medicine entitled ''Responding to Requests for Potentially Inappropriate Treatments in Intensive Care Units.'' In the statement, the term medical futility was defined more narrowly, referring only to ''treatments that have no chance of achieving the intended physiologic goal.'' The policy statement contrasts this narrow definition of futility with broader definitions that include futility based on quality-of-life judgments, stating that ''broader definitions of futility are problematic because they often hinge on controversial value judgments about quality of life or require a degree of prognostic certainty that is often not attainable.'' [44]

The Department considers the former description of medical futility—''treatments that have no chance of achieving the intended physiologic goal''—to represent a permissible instance of the denial of treatment under § 84.56 as a person with a disability for whom a treatment will not achieve the intended physiologic goal is not a qualified individual with a disability. In contrast, the denial of treatment due to ''value judgments about quality of life'' would likely constitute a prohibited denial of treatment under § 84.56(b)(1)(iii). Where futility is applied based on ''a degree of prognostic certainty that is often not attainable,'' whether this would constitute a prohibited denial of treatment would depend on if the level of prognostic certainty is less rigorous than that which would be applied to a similarly situated patient without a disability.

The Department agrees with the commenter that recipients must take into account reasonable modifications required under section 504 when evaluating whether a given patient with a disability meets this standard. For example, some clinical protocols have made use of ''therapeutic trials'' involving the provision of mechanical ventilation for a set period of time to evaluate the effectiveness of ventilator treatment for a particular patient, under which patients must meet a set

[44] G.T. Bosslet et al., *An official ATS/AACN/ACCP/ESICM/SCCM Policy Statement: Responding to Requests for Potentially Inappropriate Treatments in Intensive Care Units,* 191 a.m. J. Respiratory & Critical Care Med. 1318 (June 2015).

threshold or trajectory for continued treatment to be deemed non-futile. However, as the Department previously noted within the NPRM, patients with particular types of disabilities may take longer to respond to treatment, and the test period may need to be longer to accurately evaluate the effectiveness of mechanical ventilation for these patients. In this situation, a recipient may need to allow an individual with a disability some additional time on a ventilator to assess likely clinical improvement, unless doing so would constitute a fundamental alteration of the ventilator trial.

Comments: Several commenters asked the Department to clarify that the ongoing need for assistive technology, attendant care, or other physical assistance with activities of daily living, mechanical ventilation, supervision, or other disability support needs does not constitute sufficient reason to deny a qualified individual with a disability access to medical treatment. They also seek clarification that the fact that a person with a disability will not recover to their pre-treatment baseline is not sufficient basis to deny medical treatment that would succeed at prolonging a patient's life.

Response: The Department agrees. A recipient generally may not deny medical treatment to a qualified individual with a disability, including via a medical futility determination, simply because the patient will require ongoing support during or after receiving medical treatment. As indicated in the NPRM, people with disabilities frequently report having a good quality of life notwithstanding their need for assistance in many of the areas cited in the literature as a basis for a futility determination, such as mechanical ventilation, the use of assistive technology, the need for ongoing physical assistance with activities of daily living, mobility impairments, cognitive disability, and other similar factors. Similarly, the fact that a patient with a disability may not recover to their pre-treatment baseline is generally not sufficient basis to justify denying of medical treatment, including via a medical futility determination.

The Department noted in the NPRM that determinations that an individual with a disability's life is not worth living because of dependence on others for support or need for mechanical ventilation, intensive care nursing, tracheotomy, or other ongoing medical care rest on judgments that do not properly relate to the individual's qualification for medical treatment under section 504. Qualification for the service of life-sustaining treatment must be based on whether the treatment would be effective for the medical condition it would be treating, not broader societal judgments as to the relative value of a person's life due to their disability or whether life with a disability is worth living.

Many people with disabilities require these kinds of supports, often on a long-term basis, to survive and thrive. With such supports, individuals with disabilities can and do live many years, enjoying meaningful social, family, and professional relationships. By denying patients with disabilities the opportunity to make their own decisions regarding whether to receive or continue medically effective life-sustaining care, recipients override patient autonomy in favor of their own beliefs regarding the value of the lives of individuals with disabilities who are dependent on others or on medical equipment or technology.

Crisis Standards of Care

Comments: The Department received a broad array of comments on the application of § 84.56 to crisis standards of care.

Many comments asked the Department to confirm the application of section 504 and § 84.56 to crisis circumstances, provide additional examples of crisis standards of care obligations within the preamble or regulatory text, and respond to inquiries regarding the application of § 84.56 to these contexts.

Response: The Department confirms that section 504 and § 84.56 apply during the planning, development, activation, and implementation of crisis standards of care.

Comments: Many commenters noted that during the COVID–19 public health emergency many State crisis standards of care plans included both categorical exclusions from crisis care on the basis of specific disabilities and other instances of unfavorable treatment against people with specific disabilities (such as relative de-prioritization for scarce critical care resources). These commenters asked the Department to clarify the obligations of section 504 with respect to categorical exclusions and other instances of unfavorable treatment on the basis of specific disability diagnoses (such as cancer, cystic fibrosis, dementia, or intellectual disability) or on the basis of functional impairments (such as difficulty with activities of daily living).

Response: As indicated under § 84.56(b)(2), when a qualified individual with a disability seeks or consents to treatment for a separately diagnosable symptom or medical condition (whether or not that symptom or condition is a disability under this part or is causally connected to the individual's underlying disability), a recipient may not deny or limit clinically appropriate treatment if it would be offered to a similarly situated individual without an underlying disability. When a crisis standards of care plan indicates that patients with specific disabilities will be categorically excluded, given lower priority, or otherwise will receive unfavorable treatment when seeking access to critical care resources, this may be a denial of treatment for a separately diagnosable symptom or medical condition that would be provided to a similarly situated individual without an underlying disability. If the patient with a disability is qualified to receive such treatment, this may constitute a violation of § 84.56(b)(2). This analysis applies both to unfavorable treatment on the basis of specific diagnoses and on the basis of functional impairments that constitute disabilities under section 504.

We discuss here some relevant considerations regarding qualification to receive treatment in the crisis standards of care context. Categorical exclusions on the basis of disability in crisis standards of care are prohibited when treatment would not be futile for all individuals with that type of disability *i.e.,* that the treatment has no chance to achieve the intended physiologic goal for all persons with that particular type of disability. For example, a hospital is generally prohibited from having a categorical exclusion denying ventilator treatment to individuals with Down syndrome because ventilator treatment is not futile for all persons with Down syndrome. Deprioritization of people with disabilities compared to people without disabilities and other instances of unfavorable treatment can also constitute violations of § 84.56, if the disability receiving unfavorable treatment does not impact short-term mortality. A patient's disability should not form the basis for decisions regarding the allocation of scarce treatment for a separate medical condition or symptom, unless that underlying condition is so severe that it would prevent the treatment sought from being effective or prevent the patient from surviving until discharge from the hospital or shortly thereafter.

We note that there are instances where § 84.56 prohibits discriminatory treatment in crisis standards of care even where a patient is not seeking treatment for a separate symptom or condition but instead seeks treatment for their own underlying disability. For instance, § 84.56(b)(1) clarifies that

unfavorable treatment, including categorical exclusions and deprioritization, based on bias or stereotypes about a patient's disability; judgments that the individual will be a burden on others due to their disability, including, but not limited to caregivers, family, or society; or a belief that the life of a person with a disability has lesser value than the life of a person without a disability, or that life with a disability is not worth living are violations of § 84.56 regardless of what type of medical treatment the patient is seeking.

Comments: Many commenters asked the Department to discuss the application of section 504 and § 84.56 to instances of denial of medical treatment on the basis of judgments of long-term life-expectancy as a result of a patient's disability, a common feature of many crisis standards of care plans.

Response: As the Department has previously indicated in its February 2022 guidance, recipients may not deny or give lower priority to patients with disabilities because of a judgment that their long-term life expectancy may be lower than an individual without a disability after treatment.[45] Section 504 prohibits recipients, including those implementing crisis standards of care, from imposing or applying eligibility criteria that screen out or tend to screen out individuals with disabilities, or any class of individuals with disabilities, from fully and equally enjoying a program or activity, unless such criteria can be shown to be necessary for the provision of the program or activity being offered.[46] In the context of crisis standards of care implementation, which is designed to address resource shortages in a temporary emergency, a patient's likelihood of survival long after hospital discharge, which may depend upon many factors and may be difficult to predict, is unlikely to be related to the need to make allocation decisions about scarce resources on a temporary basis.[47] The further in the future a provider forecasts, the less likely survival has to do with the effectiveness of the medical intervention in the context of the public health emergency necessitating crisis standards of care. Judgments about long-term life expectancy are inherently uncertain and may screen out or tend to screen out individuals with disabilities from access to care without being necessary for the safe provision of the health care being offered. Given these concerns about long-term life expectancy calculations in the crisis standard of care context, denying or providing lower priority for access to scarce critical care resources based on a patient's disability impacting their long-term life expectancy when such critical care resources would be provided to a patient without such a disability may also constitute a violation of § 84.56(b)(2), insofar as it would represent a denial of medical treatment for a separate symptom or condition that would be provided to a similarly situated person without a disability. This may also violate other provisions of the section 504 regulation, including the general prohibitions against discrimination in § 84.68 and the broad prohibition against discrimination in medical treatment in § 84.56(a).

Comments: Several commenters urged the Department to clarify that crisis standards of care protocols that deny, limit, or give lower priority to people with disabilities in accessing critical care resources based on anticipated resource utilization could constitute a violation of section 504 and § 84.56.

Response: The Department agrees that such denials, limitations, or lower priority for people with disabilities than other persons for critical care resources based on resource-utilization can constitute a violation of section 504 and § 84.56. As discussed in the NPRM, practices or protocols in which recipients deny medical resources based on the projected length or scope of resources needed, and thus deny care to certain individuals with a disability because they are concerned that treating a patient with a disability may require more of a particular resource than treating individuals without a disability, may discriminate against persons with disabilities.[48]

Comments: Several commenters asked the Department to clarify that reasonable modifications may be required to assessment tools used to prioritize patients for access to critical care under crisis standards of care and to provide examples of such modifications.

Response: The Department has carefully considered the comments received and as discussed in the NPRM, recipients may be required to make reasonable modifications to prognostic scoring tools used to prioritize critical care resources under crisis standards of care, just as this obligation exists outside of crisis standards of care contexts. For instance, throughout the COVID–19 pandemic, many States and hospitals indicated they planned to make use of the Sequential Organ Failure Assessment (SOFA) to make judgments about short-term life expectancy in the event that crisis standards of care were activated. The SOFA is a composite instrument, incorporating scores from multiple other instruments into a composite score that has been used within crisis standards of care allocation to predict short-term life expectancy. Among the component instruments of the SOFA is the Glasgow Coma Scale (GCS). Application of the GCS, a tool designed to measure the severity of acute brain injuries, may not yield a valid result (*i.e.,* it may not correspond to actual mortality risk) when applied to patients with underlying disabilities that impact speech or motor movement issues. The GCS assigns a more severe score to patients who cannot articulate intelligible words or who cannot obey commands for movement. However, many disabilities result in these same attributes—such as autism and cerebral palsy—but do not contribute to short-term mortality. As a result, the use of the SOFA with patients with such underlying disabilities may lead to an unduly pessimistic prediction of short-term survival, giving such patients lower priority in accessing scarce critical care resources.

As the American Academy of Developmental Medicine and Dentistry (AADMD) notes, ''in the field of developmental medicine, there are patients who, at their natural baseline often cannot hear a command, move their limbs or communicate verbally. Given the combination of characteristics inherent in the population of people with intellectual and developmental disabilities, it would be possible to use 'objective' data surrounding the SOFA score to predict a significantly higher mortality risk than is really the case.'' [49] Similar impacts may exist for other types of disabilities and other prognostic scoring tools, measures, diagnostic instruments, and

[45] U.S. Dep't of Health & Human Servs., Off. for Civil Rts., FAQs for Healthcare Providers during the COVID–19 Public Health Emergency: Federal Civil Rights Protections for Individuals with Disabilities under section 504 and Section 1557 (Feb. 4, 2022), *https://www.hhs.gov/civil-rights/for-providers/civil-rights-covid19/disabilty-faqs/index.html.*

[46] *See* § 84.68(b)(8); 28 CFR 35.130(b)(8) (DOJ title II regulation).

[47] *See* U.S. Dep't of Health & Human Servs., Off. for Civil Rts., FAQs for Healthcare Providers during the COVID–19 Public Health Emergency: Federal Civil Rights Protections for Individuals with Disabilities under section 504 and Section 1557 (Feb. 4, 2022), *https://www.hhs.gov/civil-rights/for-providers/civil-rights-covid19/disabilty-faqs/index.html* at question 7.

[48] 88 FR 63401.

[49] Am. Acad. of Dev. Med. & Dentistry, People with Intellectual and Developmental Disabilities and the Allocation of Ventilators During the COVID–19 Pandemic (Apr. 2020), *https://static1.squarespace.com/static/5cf7d27396d7760001307a44/t/5ecfb6fff13530766aeae51a/1590671105171/Ventilator+-+Policy+Statement+w+Addendum.pdf.*

methodologies for assessment or the allocation of scarce medical resources.

The general requirement that recipients provide reasonable modifications when necessary to avoid discrimination that appears in proposed § 84.68(b)(7) applies in circumstances of scarce resources, just as it does elsewhere. Section 504 might, for example, require reasonable modifications in the administration of assessment tools such as the SOFA and the GCS (which may be used within a larger scoring rubric for the allocation of scarce resources) to ensure that the tools measure accurately what they are intended to measure in people with disabilities. For example, a scoring tool may typically assess the inability of a person to articulate words, but it would likely be discriminatory to use that determination to indicate an actual mortality risk when assessing a person with cerebral palsy because that person's pre-existing speech impairments do not imply mortality risk in the context of the acute care episode the person is seeking care for. We also note that, in general, mortality risk screening should be linked to the event that led to the acute care episode rather than an individual's pre-existing disability.

Organ Transplantation

In the NPRM, the Department noted that organ transplant discrimination against people with disabilities remains an ongoing problem. OCR's investigative experience confirms ongoing concerns about discrimination at various points in the transplant process. Medical providers and transplant programs continue to refuse to evaluate patients with disabilities who are otherwise qualified for transplant eligibility and fail to place qualified patients on transplant waiting lists because of exclusions and limitations for certain disabilities that are not supported by objective evidence or that do not take into account reasonable modifications in assessing an individual's ability to manage postoperative care needs and other aspects of transplantation. For example, in 2019, OCR resolved a case alleging discrimination against an individual with Autism Spectrum Disorder, in which the complainant alleged that a medical center deemed the patient ineligible to be considered for evaluation for placement on a heart transplant wait list because of the individual's diagnosis of Autism Spectrum Disorder and anticipated difficulties managing postoperative care. OCR worked with the recipient to enter a voluntary resolution agreement and the medical facility agreed to reevaluate the individual's eligibility for placement on the waiting list and consider the services and supports the individual could access to manage postoperative care.

Comments: Many commenters praised the Department for addressing discrimination against people with disabilities in organ transplantation and urged the Department to clarify that section 504 and § 84.56 apply to the broad scope of the organ transplantation process, including the provision of information that transplantation was an option, referral to a transplant center, evaluation by the transplant center for clinical eligibility for transplantation, evaluation for ability to manage post-operative care needs, prioritization for access to organ transplants, and other aspects of organ transplantation. They also asked the Department to include additional information and examples regarding the application of § 84.56 to organ transplant discrimination and to respond to specific inquiries.

Response: The Department agrees that organ transplant discrimination against people with disabilities remains an ongoing problem and that section 504 and § 84.56 apply throughout the organ transplantation process, including the provision of information, referrals, evaluation, eligibility, prioritization and other aspects of the transplantation process. We respond to inquiries and provide further information on the application of § 84.56, including illustrative examples, throughout this subsection.

Comments: Many commenters highlighted discrimination against people with disabilities, particularly people with developmental disabilities, seeking access to organ transplantation on the grounds that they would not be able to manage their post-operative care needs. These commenters asked the Department to indicate that evaluation for suitability of transplantation must be done taking into account modifications the patient with a disability may use to manage their post-operative care regimen, including both formal and informal supports. A commenter also asked the Department to indicate that denying a person with a developmental disability, such as intellectual disability or autism, access to organ transplantation because the recipient believes the person with a disability would not be able to maintain the strict regimen necessary to avoid organ rejection would constitute a violation of § 84.56(b)(1), which prohibits denial of medical treatment based on biases or stereotypes on the basis of a person's disability. Another commenter described a patient with a disability being denied access to transplantation due to concerns on the part of the transplant center that their supporter also had a disability and would not be able to provide the patient with adequate assistance after their operation due to the supporter's disability.

Response: The Department agrees that denying a person with a developmental disability access to organ transplantation because the recipient believes the person with a disability would not be able to manage their post-operative care needs may violate § 84.56(b) if this assessment did not take into account modifications the patient may make use of, such as reliance on formal and informal care and other supports. Such a denial could constitute a violation of § 84.56(b)(1), if motivated based on biases or stereotypes about the patient's disability. However, even where this denial is not the result of biases or stereotypes regarding a patient's disability, it may be prohibited by other provisions of this rule. For example, a transplant center that conducts an individualized evaluation of a patient with a developmental disability and concludes they would be unable to manage their post-operative care needs independently may not have done so as a result of biases or stereotypes. However, by not considering within their evaluation the patient's ability to manage their post-operative care needs with support from family, service-providers or others in the patient's circle of support, a recipient may violate § 84.68(b)(7), which requires reasonable modifications to policies, practices and procedures for people with disabilities, and § 84.56(b)(2), as evaluating whether a person with a disability is qualified to receive a transplant and/or similarly situated to a person without a disability who would receive an organ transplantation must be done taking into account the reasonable modifications the patient with a disability may utilize in order to meet qualification standards.

Clinical Research

Clinical research participation can offer considerable benefit to both the individuals participating and society at large. In addition to the intangible benefits of advancing scientific discovery and contributing to the development of potential medical interventions, those participating in clinical research are often able to obtain access to diagnostic, preventative, or therapeutic interventions and treatments that would not otherwise be available to them. The unnecessary exclusion of people with disabilities from clinical research harms those who

are denied the direct benefits of research participation. It also threatens the generalizability of research findings and potentially the reach of subsequent medical innovations for those groups who are excluded.

Recent research has documented that people with disabilities face systemic and unnecessary exclusion from clinical research.[50] Although study exclusions and other restrictions in eligibility criteria can be justifiable in appropriate cases based on the nature of the clinical research being conducted, they can also be the result of a failure to take into account the availability of reasonable modifications to a study protocol that might permit the participation of people with disabilities. It also may be the result of overly narrow eligibility criteria rooted in stereotypes, bias, or misunderstandings of the capabilities of people with specific disabilities. Investigators may have valid reasons for excluding people whose disabilities are medically incompatible with the study being conducted. When evaluating potential study participants on an individualized basis, clinical judgment may be necessary on the part of the investigator to assess the appropriateness of study participation. However, it is important that study eligibility criteria be written in a way that does not unnecessarily screen out people with disabilities whose research participation would not alter the intended purpose of the program of clinical research being undertaken.

Similarly, overly narrow eligibility criteria that unnecessarily screen out people with disabilities may be motivated by concerns regarding the ability of potential study participants with disabilities to perform research-related tasks that can be reasonably modified, such as filling out tests or responding to instructions from research personnel, or by the failure to take into account the recipient's obligation to provide for effective communication or make reasonable modifications for people with disabilities.

Many commenters appreciated the specific application of section 504, including § 84.56, to clinical research activities in the proposed rule, and asked the Department to provide further examples and respond to queries regarding the application of section 504, including but not limited to § 84.56, to clinical research. Some commenters provided specific examples of discrimination on the basis of disability in clinical trials, including on the basis of leukemia, multiple sclerosis, HIV, obesity, muscular dystrophy and other neuromuscular diseases as well as other diagnoses. Many examples focused on the negative consequences of being denied access to clinical research on those people with disabilities turned away.

Other commenters focused on the adverse implications on society as a whole of excluding people with disabilities from clinical research. For instance, some commenters noted the impact of clinical research in value assessment activities that inform payer activities regarding utilization management and the coverage of particular medical interventions for specific patient populations. (We further discuss the intersection of clinical trial exclusions on the basis of disability and utilization management decisions by payers elsewhere within this subsection.) Others noted that the exclusion of people with disabilities from clinical research may contribute to a lack of information on differences in the efficacy, effectiveness, and side effects profiles of medical interventions being studied.

Response: As indicated elsewhere in this section, the Department considers § 84.56 to apply to clinical research activities of recipients. The provision of § 84.56 that is most likely to be relevant to clinical research is § 84.56(b)(2), which prohibits denying or limiting treatment for a separately diagnosable symptom or medical condition if it would be offered to a similarly situated individual without an underlying disability. In addition, section 504 regulations include other provisions that apply to clinical research activities. For example, § 84.68(b)(8) prohibits imposing or applying eligibility criteria that screen out or tend to screen out individuals with disabilities or classes of individuals with disabilities from ''fully and equally'' enjoying any program or activity, unless the criteria can be shown to be necessary for the provision of the program or activity being offered. However, the Department notes that application of each of these provisions is fact-dependent. As the Department noted within the NPRM, the use of eligibility criteria that screen out or tend to screen out people with disabilities from clinical research can constitute a violation of this provision.

For example, assume that a researcher employed by an entity receiving Federal financial assistance develops a protocol for use in clinical research evaluating a new intervention for diabetes care. The researcher articulates inclusion and exclusion criteria for the study and includes a requirement that study participants must not have a visual impairment, based on the determination that patients with diabetes-related visual impairments would be medically contraindicated from making use of the intervention. Potential study participants with any form of visual impairment are excluded, even if their blindness is not indicative of a stage of diabetes disease progression that would preclude treatment effectiveness. Prohibiting a qualified individual with a disability from participating in a clinical research program based on a broad-based categorical judgments related to a disability likely violates section 504, where such categorical exclusion criteria are not necessary for the implementation of the study, as doing so screens out individuals with disabilities from participating in a program of clinical research and is not necessary for the operation of the research program. In contrast, a researcher in similar circumstances who excludes only patients with diabetes-related visual impairments that are likely to impact eligibility for the study because of the clinical appropriateness of receiving the treatment being studied is not likely to be unnecessarily screening out individuals with disabilities, as excluded patients are only those who are medically contraindicated for the treatment. In addition, the obligation articulated in § 84.68(b)(7) to make reasonable modifications to policies, practices, or procedures when necessary to avoid discrimination unless the modification would fundamentally alter the nature of the program or activity at issue also applies to clinical research.

In some instances, excluding people with disabilities from clinical research may implicate further provisions of the section 504 regulations. For example, a researcher who prohibits patients with cognitive disabilities from participating in a research study regarding cancer treatment based on a belief that they would not be able to provide informed consent could violate § 84.56(b)(1)(i), as it constitutes a denial of medical treatment to a qualified individual with a disability based on stereotypes regarding a patient's disability, § 84.56(b)(2), as it constitutes a denial of treatment for a separate symptom or condition that would be offered to a similarly situated person without a disability, and § 84.68(b)(7) as concerns about informed consent could be

[50] Willyanne DeCormier Plosky et al., *Excluding People with Disabilities from Clinical Research: Eligibility Criteria Lack Clarity and Justification,* 41 Health Aff. 10 (Jan. 2022). *https://doi.org/10.1377/hlthaff.2022.00520;* Katie McDonald et al., *Eligibility Criteria in NIH-funded Clinical Trials: Can Adults with Intellectual Disability Get In?* 15 Disability & Health (2022), *https://doi.org/10.1016/j.dhjo.2022.101368.*

addressed through a reasonable modification permitting the prospective study participant with an intellectual disability to use supported decision-making by bringing a friend or family member to help study staff explain the study risks and benefits to them.

Comments: One comment from an academic research center focused on clinical trials requested the Department replace the phrase ''exclusion criteria'' for ''eligibility criteria'' as the exclusion of people with disabilities from clinical research may take place both through explicit exclusion criteria and through overly narrow inclusion criteria or other components of a study protocol that result in the unnecessary exclusion of people with disabilities. They ask the Department to clarify that the obligations of section 504 apply to the broad scope of a study protocol and clinical research activities, not just exclusion criteria. Another commenter noted that people with disabilities are often excluded from clinical trials due to the use of clinical end points that are consistent with prior research studies but not necessary for the program of clinical research currently being undertaken.

Response: The Department agrees that the unjustified exclusion of people with disabilities from clinical research can take place through explicit exclusion criteria, overly narrow inclusion criteria, and through other aspects of a study protocol or clinical research activities that unnecessarily screen out people with disabilities. We have revised the preamble language throughout to clarify this point and include other information on potential ways in which section 504 applies to clinical research.

Comment: Another commenter requested that the Department require organizations conducting clinical research and the Food and Drug Administration (FDA) show the exclusion of individuals with disabilities within the study population is necessary for the success of the study and not simply a continuation of a previous practice chosen for simplicity.

Response: As indicated above, section 504 regulations require eligibility criteria to not screen out or tend to screen out people with disabilities from a clinical research program unless the criteria can be shown to be necessary for the provision of the program or activity being offered. Section 84.56 operationalizes this through multiple specific prohibitions, which we have articulated above. If recipients specifically exclude populations of persons with disabilities from their clinical research, they should articulate clear rationales for those populations of people with disabilities who are excluded to ensure that such exclusions are necessary for the provision of the program or activity of clinical research being conducted.

Comment: A commenter described a scenario in which a patient was denied access to a clinical trial for a mental health treatment they were otherwise qualified for because the program required periodic imaging and the imaging equipment affiliated with the program had a low weight capacity that could not accommodate the patient's obesity. They sought and were denied a reasonable modification of using other imaging equipment available to the medical center that was not typically utilized in the clinical trial. They asked how section 504 would apply to this situation.

Response: Whether the scenario described by the commenter constitutes a violation of section 504 is fact-dependent.[51] Sections of the rule that would need to be considered would include § 84.56(b)(2), as the patient was seeking treatment for a separate medical symptom or condition and was denied it when it would have been provided to a similarly situated patient without a disability, and § 84.68(b)(7), which requires reasonable modifications for people with disabilities. Recipients conducting clinical trials have an obligation to make reasonable modifications for people with disabilities, including using available accessible equipment elsewhere within a facility, unless they would constitute a fundamental alteration of the program or activity being offered. As indicated within the NPRM, the exclusion of people with disabilities from clinical research may also constitute a violation of § 84.68(b)(8), which prohibits imposing or applying eligibility criteria that screen out or tend to screen out individuals with disabilities or classes of individuals with disabilities from ''fully and equally'' enjoying any program or activity, unless the criteria can be shown to be necessary for the provision of the program or activity being offered.

Comment: Some commenters asked the Department to clarify that unnecessarily excluding people with disabilities from clinical research not related to their disability may constitute discrimination.

Response: The Department agrees that section 504 applies to clinical research both relating to a patient's disability and not related to a patient's disability.

Comment: Several commenters asked OCR to consider issuing sub-regulatory guidance in collaboration with other parts of the Federal Government, including the National Institutes of Health and the FDA, regarding the application of section 504 to clinical research activities.

Response: The Department will consider issuing guidance and providing technical assistance regarding the application of section 504 to clinical research in the future.

Examples Regarding § 84.56(b)(1)

Many commenters requested the Department add additional prohibited rationales for discrimination to the regulatory text of § 84.56(b)(1), which provides a non-exhaustive list of prohibited rationales for denying or limiting medical treatment to a qualified individual with a disability and applies broadly (regardless of whether a patient is seeking treatment for their underlying disability or for a separate symptom or condition). The Department responds to these requests and for other clarifications regarding the application of § 84.56(b)(1) in this subsection.

Comment: One commenter requested that the Department add to § 84.56(b)(1) language prohibiting denying or limiting medical treatment to a qualified individual with a disability based on a belief that providing care for a patient with a disability would constitute a suboptimal use of recipient resources, unless the same judgment would be made about a patient who did not have a disability.

Response: The Department agrees that a denial or limitation of treatment based on a belief that providing care for a patient with a disability would constitute a suboptimal use of recipient resources, where the same judgment would not be made about a similarly situated patient who did not have a disability, would likely be prohibited discrimination under § 84.56. However, the Department believes that this conduct is already addressed under § 84.56(a) and other sections of § 84.56. Where the treatment being sought is for a separate medical symptom or condition, it is prohibited under § 84.56(b)(2). Such action would likely also be prohibited under § 84.56(b)(1)(iii), which prohibits discrimination based on a belief that the life of a person with a disability has lesser value than the life of a person without a disability, or that life with a disability is not worth living.

[51] We encourage any person who believes they or another party has been discriminated against on the basis of race, color, national origin, sex, age, or disability, to visit the OCR complaint portal to file a complaint online at: *https://www.hhs.gov/civil-rights/filing-a-complaint/index.html.*

Comment: Several commenters requested that the Department clarify that § 84.56(b)(1)(i) extends to the denial or limitation of medical treatment based on biases and stereotypes regarding particular medical treatments for a disability because such biases and stereotypes originate with beliefs about a patient's disability.

Response: The Department agrees that biases and stereotypes regarding particular medical treatments can constitute biases and stereotypes regarding the disability of the patients that receive them. For example, biases and stereotypes regarding antiretroviral therapy may constitute discrimination against persons with HIV. Similarly, biases and stereotypes regarding Medication Assisted Treatment for Opioid Use Disorders could constitute discrimination against persons with Opioid Use Disorders.

Comment: Several commenters requested that the Department add to the regulatory text of § 84.56(b)(1) language prohibiting denying or limiting medical treatment to a qualified individual with a disability based on whether a patient has an advance directive.

Response: Where a recipient denies medical treatment to persons with disabilities because they do not have an advance directive, but does not do so for persons without disabilities who do not have an advance directive, such a denial or limitation would likely violate the general prohibition on discrimination on the basis of disability in § 84.56(a) and may also constitute prohibited discrimination under § 84.56(c)(2)(ii), which prohibits discrimination against a qualified individual with a disability on the basis of disability in seeking to obtain consent from an individual or their authorized representative for the recipient to provide, withhold, or withdraw treatment. We made this point explicitly in several examples in the NPRM, where we indicated that a covered hospital may not repeatedly request that a patient with a disability (or the patient's legally authorized representative) consent to a do-not-resuscitate order, where it would not make such repeated requests of a similarly situated nondisabled patient. In addition, we noted that a recipient may not condition access to treatment on a patient with a disability or their authorized representative agreeing to a particular advanced care planning decision when they would not implement or enforce such a requirement on a similarly situated nondisabled patient. As such, we believe the circumstances described by the commenter are already prohibited by the regulation and have elected not to modify the regulatory text of § 84.56(b)(1).

Comment: Several commenters asked the Department to clarify that prohibited discrimination under § 84.56(b)(1)(i) could emerge both from biases and stereotypes regarding a single disability diagnosis possessed by the patient or from the interaction of multiple diagnoses and perceived complexity of these diagnoses.

Response: The Department agrees that the phrase ''a patient's disability'' under § 84.56(b)(1)(i) describes both biases and stereotypes about a single disability diagnosis as well as biases and stereotypes about multiple disabilities.

Comment: Several commenters requested the Department include examples of denials or limitations due to fears about one's own health due to the treatment of the person with the disability as instances of prohibited discrimination under § 84.56(b)(1).

Response: The Department agrees that unfounded fears about one's own health due to the treatment of the person with the disability are already prohibited as biases or stereotypes about a patient's disability under § 84.56(b)(1)(i). Where such fears have a reasonable basis in fact, a recipient would only be permitted to deny or limit access to a program or service they offer if they meet the threshold for a direct threat articulated under § 84.75 (see that section for a more detailed discussion).

Comment: Several commenters requested the Department clarify that a refusal to provide a referral on the basis of disability status, including based on the factors articulated in § 84.56(b)(1), could constitute prohibited discrimination under § 84.56.

Response: The Department agrees that a refusal to provide a referral to a qualified individual with a disability could constitute prohibited discrimination, as such a refusal would be a limitation on the medical treatment provided to a qualified individual with a disability. The Department previously noted within the NPRM that when a provider would typically provide a referral to another provider for whom a given treatment is within their scope of practice, a refusal to provide such a referral on the basis of disability would likely constitute a violation of § 84.56.

Comment: Several commenters asked the Department to use the term ''individual'' rather than ''patient'' to clarify the broad application of § 84.56, as certain things that the Department has clarified are considered medical treatment under § 84.56 generally do not involve referring to consumers of services as ''patients.''

Response: While the Department has elected to retain the current regulatory text, we clarify here that the term ''patient'' is intended to be interpreted broadly to refer to any individual with a disability that seeks to access services included under the definition of medical treatment. We use the term ''patient'' and ''individual'' interchangeably throughout the final rule.

Comment: Several commenters requested that the Department clarify that the application of § 84.56(b)(1)(iii), which prohibits denying or limiting medical treatment to a qualified individual with a disability when the denial is based on ''a belief that the life of a person with a disability has lesser value than the life of a person without a disability, or that life with a disability is not worth living,'' includes denials or limitations based on assumptions about a person with a disability's quality of life, as that terminology is more commonly used by health care providers.

Response: The Department agrees that treatment denials or limitations to qualified individuals with disabilities based on a provider's belief that a person with a disability's quality of life is such that their life is not worth living due to their disability would constitute a violation of § 84.56(b)(1)(iii). We do note, however, that people with disabilities retain their right to decline treatment for any reason and recipients that do not provide treatment declined by the person with a disability are not in violation of this section, provided that the acquisition of consent to decline such treatment was not acquired in a discriminatory fashion (as we discuss in § 84.56(c)(2)(ii)).

Comment: A commenter requested the Department clarify that § 84.56(b)(1) includes an additional instance of prohibited discrimination in the regulatory text, stating that discrimination is also prohibited on the basis of a belief that the extra accommodation, expense, or time required for treatment related to the individual's disability is not justified.

Response: The example cited by the commenter is covered by the existing regulatory text, as § 84.56(b)(1)(ii) clarifies that discrimination on the basis of judgments that an individual will be a burden on others due to their disability, including, but not limited to caregivers, family, or society are prohibited under section 504. Denying an extra accommodation, expense, or time required for treatment related to a person's disability because of the belief that the individual will be a burden to society would be covered as an instance

of discrimination based on a judgment that an individual will be a burden on others due to their disability, as the additional accommodation, expense, or time required for treatment related to a person's disability constitutes an example of burden on others.

For example, a recipient that denies surgery to a person with a mobility disability that would typically be provided to a person without a mobility disability based on a belief that the additional expense required to accommodate a person with such a disability in ongoing medical treatment after their surgery would constitute a burden on the medical system as a whole would likely be in violation of § 84.56(b)(1)(ii). Similarly, the Department has previously indicated within the NPRM that § 84.56(b)(1)(ii) would be violated if an individual with a disability needed a medically indicated surgical procedure but it was denied because of a recipient's judgment that the postoperative care the patient would need after the surgery because of the patient's disability would be an unfair burden on the individual's caregivers, family, or society.

Comment: Several commenters requested that the Department clarify that denials or limitations of medical treatment that are seemingly based on nondiscriminatory rationales, but where evidence demonstrates they are actually motivated by discriminatory rationales, are prohibited under § 84.56.

Response: Proving the discriminatory intent of a recipient where a recipient offers a nondiscriminatory rationale is a fact-dependent proposition and requires nuanced judgment. Where a recipient offers a nondiscriminatory rationale for denying medical treatment, but that rationale is inconsistent with the evidence in the specific case, it may constitute discrimination under § 84.56.

Comment: Many commenters asked the Department to clarify that the prohibitions listed under § 84.56(b), including § 84.56(b)(1), are not exhaustive and that other instances of prohibited discrimination are encompassed under § 84.56(a).

Response: The Department agrees that the prohibitions listed under § 84.56(b), including § 84.56(b)(1), are not exhaustive and that other instances of prohibited discrimination are encompassed under § 84.56(a).

Separately Diagnosable Symptom or Medical Condition

As indicated within the NPRM, in order to align with what we believe to be the correct reading of the statute and the case law, the Department adopted distinct standards for circumstances under which a qualified person with a disability is denied medical treatment for the disability that triggers coverage under section 504 (referred to as an ''underlying disability'') or for a separately diagnosable symptom or condition for which the patient seeks treatment. As the general prohibition against discrimination against people with disabilities seeking medical treatment in § 84.56(a) applies broadly to both such instances, we provide specific examples of some of the instances of prohibited discrimination that do not require a separately diagnosable symptom or condition in § 84.56(b)(1), including biases or stereotypes about a patient's disability, judgments that the individual will be a burden on others due to their disability, and a belief that the life of a person with a disability has lesser value or that life with a disability is not worth living. While this is not an exhaustive list, we believe it provides a useful illustration of the types of discrimination that are prohibited regardless of whether a person with a disability is seeking medical treatment for the underlying disability that triggers coverage under section 504 or for a separately diagnosable symptom or condition.

In § 84.56(b)(2), the Department prohibits denying or limiting clinically appropriate treatment for a separately diagnosable symptom or medical condition (whether or not that symptom or condition is a disability under this part or is causally connected to the individual's underlying disability) if it would be offered to a similarly situated individual without an underlying disability. Examples of circumstances in which such denials could occur include when a person with Down syndrome might seek a heart transplant to address a heart condition; a person with spinal muscular atrophy might seek treatment for a severe case of COVID–19; or a person with a spinal cord injury might seek treatment for depression with suicidal ideation.

Instances of discrimination against people with disabilities in medical treatment contexts may violate multiple paragraphs of § 84.56, including paragraphs (b)(1) and (2). For example, should a recipient deny a referral for a medically indicated heart transplant to a patient with a mental health condition because of a biased belief that persons with mental health disabilities represent a danger to society and should thus not be permitted to access scarce medical resources, this would likely constitute a violation of both provisions. Because the recipient has denied access to medically indicated treatment based on biases or stereotypes about a patient's disability, they have likely violated § 84.56(b)(1), and because this treatment was for a separately diagnosable symptom or medical condition and would have been provided to a similarly situated person without schizophrenia, it likely constitutes a violation of § 84.56(b)(2).

The Department solicited comments on the distinction between a separately diagnosable symptom or condition and the underlying disability, noting that this line may be more difficult to draw than in these examples, and welcomed comment on the best way to clarify this distinction. Commenters expressed a variety of perspectives on this distinction.

Some commenters questioned the choice to have two provisions both relating to the denial of medical treatment, suggesting that doing so could create unnecessary challenges for recipients and people with disabilities. Some commenters argued that attempts to distinguish between treatment for an underlying disability as opposed to for a separate condition is not the best or appropriate means of eliminating discrimination because a symptom or condition may not always be readily distinguishable from the underlying condition, particularly for persons with complex medical conditions that interact with each other and who are receiving medical treatment that is responsive to multiple different diagnoses, symptoms, or conditions. They suggested that the Department either avoid making this distinction or clarify it through future sub-regulatory guidance. Similarly, some commenters pointed out that separately diagnosable symptoms or medical conditions are not always readily distinguishable from underlying conditions. They expressed concern that disentangling different diagnoses from one another is at times impossible and often inadvisable, as the distinction between different diagnoses is often blurred in the clinical context and within the experiences of people with disabilities. Some felt that having two standards could lead to confusion and perhaps unnecessary litigation. Other commenters felt that the distinction made by the Department was appropriate and workable in order to both comply with applicable case law and protect people with disabilities from discrimination on the basis of disability in medical treatment. These commenters indicated that they did not believe that further efforts to distinguish between or define the different circumstances articulated between paragraphs (b)(1) and (2) of § 84.56 were necessary or useful.

Independent of their views on the distinction drawn by the Department in § 84.56(b)(2), many commenters provided examples of situations where individuals with underlying disabilities were denied treatment for separately diagnosable symptoms or conditions. They described denials of all types of treatment to individuals with mental health disorders, noting that some drug and alcohol treatment centers have a blanket policy of denying admission to individuals with mental health disabilities as well as to individuals with developmental disabilities. They also pointed to mental health facilities that routinely deny treatment to individuals with substance use disorders. Other examples included denial of routine eye exams, colonoscopies, braces and other dental services, mental health treatment, and surgical services to individuals with developmental disabilities, including intellectual disability and autistic persons. One individual described the failure of physicians to perform hip dysplasia surgery on her brother who had Down syndrome. Another described her child being refused treatment for a broken bone because he had cerebral palsy. Others described the denial of preventative screening for sexually transmitted diseases, the failure to provide information on reproductive health options, and the failure to provide care for life threatening diseases on the basis of disability.

Response: After careful consideration, the Department has elected to maintain the distinction between paragraphs (b)(1) and (2) § 84.56, recognizing that applicable case law is most appropriately interpreted as requiring a different legal standard for circumstances where a person with a disability is seeking treatment for their underlying disability as compared to when they seek treatment for a separately diagnosable symptom or condition.[52]

The Department notes and appreciates the concerns raised by commenters who argue that distinguishing between an underlying disability and a separate symptom or medical condition may be very difficult for persons with complex medical conditions that interact with each other and who are receiving medical treatment that is responsive to multiple different diagnoses, symptoms or conditions. As such, we wish to clarify that the definition of a separately diagnosable symptom or condition should be interpreted in a broad and inclusive fashion. Patients who are receiving medical treatment that is at least in part due to a separately diagnosable symptom or condition qualify for the protections of § 84.56(b)(2), even if their medical treatment is also responsive to their underlying disability. For instance, a patient with both opioid use disorder and depression who seeks mental health treatment may seek counseling from a provider that will take into account both of these diagnoses. Should the provider discriminate against this patient as a result of their diagnosis of opioid use disorder, this would implicate the protections of § 84.56(b)(2) as depression constitutes a separately diagnosable symptom or condition, despite the fact that the treatment sought would likely have taken into account and sought to treat both of the patient's diagnoses.

We reiterate that this provision does not require the separately diagnosable symptom or medical condition to be entirely unrelated to the underlying disability; it is instead intended to reach circumstances in which the condition for which medical treatment is sought is sufficiently distinct from the underlying disability such that the person with the disability can be considered similarly situated to a person without the disability for treatment purposes. For example, that a separately diagnosable heart condition is related to an underlying disability in some manner is irrelevant under the proposed rule if the underlying disability makes no difference to the clinically appropriate treatment for the heart condition. This approach is consistent with the mandate that persons with disabilities be accorded equal treatment under section 504. Similarly, a symptom or condition that arises from a common underlying biological mechanism as a patient's underlying disability, such as Kaposi's sarcoma in a person with AIDS, is a separately diagnosable symptom or condition for the purposes of this section. As we indicated within the NPRM, it does not matter for these purposes whether the condition for which the individual is seeking treatment is in some sense causally related to the underlying disability if the decision to refuse treatment would not be made as to similarly situated individuals without the disability. Individuals with Down syndrome are more likely to experience heart conditions, and a spinal cord injury may be the event that triggers an individual's depression. But a refusal to treat a heart condition because the patient has the underlying disability of Down syndrome, or a refusal to treat depression because of a patient's underlying spinal cord injury, will likely violate this paragraph if treatment would be provided to a similarly situated person without an underlying disability.

We note also that it does not matter whether the symptom or condition for which the individual is seeking treatment is also a disability under section 504. Individuals with heart conditions, COVID–19, and depression could all meet the definition of an individual with a disability on the basis of these conditions in appropriate circumstances, but it is people who experience discriminatory treatment for these conditions based on an underlying disability who are entitled to the protections of § 84.56(b)(2).

Comment: Some commenters expressed that the prohibition against denying a person with a disability treatment for a separate symptom or condition does not adequately consider the complexity of caring for someone living with disability who also has multiple chronic conditions or from tailoring treatment plans to align to the patient's wishes in the interests of avoiding unnecessary suffering. One commenter put forward the example of someone who has diabetes, kidney disease, AFib, and osteoarthritis that has led to their using a walker or other assistive device who suffers from kidney failure. They indicate their view that ''the appropriate first step would be to engage in discussions about what matters to the individual and their overall prognosis based on the totality of their disease burden. In instances where they lack capacity and there is no proxy, the case should be referred to an Ethics Committee or other decision-making body as organized by the health system where the patient is receiving care.'' Another commenter also expressed concern regarding patients who are incapacitated and lack advance directives. A pharmaceutical industry group requested that the Department provide additional guidance as to the definition of ''similarly situated'' in § 84.56(b)(2). They ask that the Department clarify if an individual would be considered ''similarly situated'' to another individual with the same symptom or condition if treatment for that symptom or condition is not clinically appropriate for individuals with a certain disability or a symptom or condition that is causally connected to that disability.

Response: Determining whether a denial of treatment would constitute a violation of § 84.56(b)(2) is a fact

[52] The NPRM included a discussion of the case law concerning medical treatment decisions when the medical treatment may have been associated with the patient's disabling condition. *See* 88 FR 63403 (Sept. 14, 2023).

specific, individualized inquiry. Section 84.56(c)(1) indicates that nothing in this section requires the provision of medical treatment where the recipient has a legitimate, nondiscriminatory reason for denying or limiting that service or where the disability renders the individual not qualified for the treatment. For example, a recipient may take into account a patient's underlying disability to deny a medical treatment based on their judgment that the treatment would not be effective at accomplishing its intended effect or because an alternative course of treatment to the one that would typically be provided to patients without disabilities would be more likely to be successful in light of a patient's disability. However, this section also makes clear that the criteria articulated in § 84.56(b)(1), including a judgment that a patient's life with a disability is not worth living, is not a legitimate nondiscriminatory reason for denying or limiting treatment and cannot render a person with a disability not qualified for treatment.

As discussed elsewhere within this section, determinations that an individual with a disability's life is not worth living because of the need for ongoing support rest on judgments that do not properly relate to the individual's qualification for medical treatment under section 504. Similarly, an individual cannot be deemed not similarly situated because they require ongoing support during or after treatment that another individual does not need. Qualification for the service of life-sustaining treatment must be based on whether the treatment would be effective for the medical condition it would be treating, not broader societal judgments as to the relative value of a person's life due to their disability or whether life with a disability is worth living. In the example cited by the commenter, while the patient or their authorized representative may make a decision to decline treatment, a decision by the recipient—including where such a decision is made via an Ethics Committee—to deny medically indicated treatment based on the patient's disabilities of diabetes, kidney disease, AFib, and osteoarthritis or their use of assistive technology would likely constitute discrimination on the basis of disability if it was motivated based on a belief that continued life would not be of benefit to the patient due to their disabilities (*i.e.,* that life with their disability is not worth living).

In contrast, should a decision be made to deny treatment due to a patient's expressed wishes or those of their authorized representative, this would likely not constitute discrimination, provided that the recipient has not discriminated on the basis of disability in seeking consent to decline further treatment. Similarly, a decision to deny treatment because it would not be medically effective at prolonging the patient's life would not be in violation of this section, even if it was sought after by the patient or their authorized representative, as a patient for whom a treatment would not be medically effective is not similarly situated to a patient for whom a treatment would be medically effective.

Comments: Many commenters raised the issue of diagnostic overshadowing, in which physicians and other health care professionals attribute medical problems to a patient's underlying disability when they actually relate to a separate medical condition, resulting in underdiagnosis and a failure to diagnose or appropriately treat the separate condition. They ask the Department to clarify that diagnostic overshadowing can constitute a violation of § 84.56(b)(2) or other parts of § 84.56 when recipients depart from the standard of care by attributing all problems or symptoms of a patient with a disability to one diagnosis.

Response: Departures from the standard of care by attributing all problems or symptoms experienced by a patient with a disability to a single diagnosis could constitute discrimination under § 84.56(b)(2) under some circumstances. In the event that such diagnostic overshadowing is the result of biases and stereotypes, it could also violate § 84.56(b)(1)(i). Determining whether any individual instance rises to the level of discrimination is fact-dependent and will depend on the specific circumstances of a provider's behavior and the information available to them.

Comments: Many commenters described medical care providers, in particular mental health treatment providers, who refuse to serve patients with disabilities with comorbidities. They offer as an example drug and alcohol treatment centers that deny services to individuals with mental illness and mental illness providers that refuse to serve those with a history of drug or alcohol use disorders. The commenters ask for clarification if this might constitute discrimination under § 84.56(b)(2).

Response: A blanket prohibition on serving persons with co-occurring disabilities may constitute a violation of § 84.56(b)(2). Recipients should generally seek to ascertain whether patients with co-occurring disabilities are qualified for the purposes of the program or service in question through an individualized determination. Determining whether any specific policy or denial rises to the level of discrimination is fact-dependent and will depend on the specific circumstances of a provider's policies and behavior.

Provision of Medical Treatment

Section 84.56(b)(3) proposed to address the discriminatory provision of medical treatment. It states that if a medical professional provides an individual with a disability different treatment than the professional would provide an individual without a disability seeking assistance with the same condition—and there is nothing about the disability that impairs the effectiveness, or ease of administration of the treatment itself or has a medical effect on the condition to which the treatment is directed—then § 84.56(b)(3) has been violated. For example, if a woman with an intellectual disability seeks a prescription for contraception but her provider, due to a belief that any children she may have are likely to have an intellectual disability, offers only surgical sterilization, the recipient has likely violated § 84.56(b)(3) if the provider prescribes contraception for her other patients without disabilities. However, § 84.56(b)(3) does not prohibit a recipient from providing an individual with an underlying disability services or equipment that are different than that provided to others with the same condition when necessary to provide an effective service or treatment to the individual with a disability. Where, for example, an individual recovering from a foot or leg injury or surgery has an anatomical loss of an arm and is unable to use crutches as a result, it would likely not violate § 84.56(b)(3) to recommend or prescribe a knee scooter to the patient even though the recipient recommends crutches to most patients in this situation.

Similarly, where an underlying disability would interfere with the efficacy of a particular treatment, a recipient could provide a person with that disability a different treatment than it would provide to similarly situated nondisabled individuals. For example, an underlying health condition that itself is a disability might require an individual to take a medication that is contraindicated with a particularly effective antiviral drug. If that individual contracts COVID–19, it would likely not violate this section for a recipient to offer a different treatment than the contraindicated antiviral drug, even if it is generally less effective. Because the underlying disability would

directly inhibit the utility of the generally more effective drug, the individual would likely not be qualified for that treatment under this part.

Comments: A group of commenters representing persons with disabilities and various civil rights groups said that our example of involuntary sterilization is too narrow. They suggested that the Department make clear that the prohibition in § 84.56(b)(3) extends to any procedures whose expected and actual effect is sterilization. They recommended including situations where individuals with disabilities are pressured to use contraceptives, particularly long-acting forms, that they do not want. A significant number of commenters said that individuals with disabilities must be offered comprehensive and non-coercive contraceptive counseling about all contraceptive options, consistent with that which is offered to individuals without disabilities. These commenters recommended that individuals with disabilities also be offered comprehensive and non-coercive access to assistive reproductive technology and other fertility treatments. Many commenters said that individuals with disabilities must be able to decide if when or how to become parents.

Multiple commenters raised questions regarding the application of § 84.56 to reproductive health services. Many commenters described experiences of discrimination in accessing reproductive health care, both through the denial of treatment and through the provision of or pressure to accept inappropriate or unwanted treatment on the basis of disability. Many commenters indicated greater difficulty getting access to screening for sexually transmitted infections, mammograms, and other necessary preventative health screenings relating to reproductive health as a result of their disabilities. Other commenters reported pressure to accept sterilization or abortion as a result of their disabilities.

Response: The Department agrees that the listed examples could constitute violations of § 84.56(b)(3). For instance, requiring a patient with an intellectual disability to accept long-acting contraception, sterilization, or abortion as a result of their disability would likely constitute a violation of § 84.56(b)(3), if such a requirement would not be imposed on patients without disabilities. The Department notes that the discriminatory denial of these same treatments on the basis of a patient's disability could constitute a denial of § 84.56(b)(2), reinforcing the importance of understanding the preferences of patients with disabilities and being responsive to them, consistent with established norms for patient care for patients without disabilities. As discussed elsewhere, the Department's investigations of specific complaints regarding violations of § 84.56 will be fact-dependent.

We agree that § 84.56(b)(3) would likely be violated when a procedure has an expected and actual effect of sterilization and the circumstances otherwise fit the language of paragraph (b)(3). This could include pressuring individuals to use unwanted contraception, particularly long-acting forms of contraception, which would also likely represent a violation of the broad based prohibition against discrimination articulated in § 84.56(a).

Failure to provide comprehensive information about and access to all forms of contraception and failure to provide comprehensive information and access to assistive reproduction technology and other treatments related to infertility to qualified persons with disabilities by a recipient that provides such treatment would likely violate § 84.56(a) or (b)(2) if the recipient provides or would provide the same information and access to an individual without a disability. Denial or limitation of treatment or accompanying comprehensive information (which we consider to be part of the broad service of medical treatment) based on disability by a recipient that provides such treatment would likely constitute a violation of the general nondiscrimination in medical treatment requirement in § 84.56(a) as well as § 84.56(b)(2) which prohibits denials or limitations of treatment for a symptom or condition such as infertility that is separately diagnosable from the underlying disability motivating different treatment. For example, should a patient with an intellectual disability not be informed of the availability of infertility treatment when such information would be provided to a patient without an intellectual disability seeking treatment for infertility, this may constitute a violation of these provisions. We note that some of the described actions may also be a violation of the prohibition against sex discrimination contained in section 1557.[53]

We note that there may be instances where medical interventions which have the effect of sterilization may be medically necessary. Under such circumstances, the provision of a medical intervention that has the effect of sterilization to a person with a disability could nonetheless constitute a violation of this section if the patient with a disability has not provided informed consent to the procedure, as informed consent requirements would be applied and abided by for similarly situated patients without disabilities.

Other Laws

Comments: Several commenters asked that we state clearly that Federal laws and regulations supersede State laws including those allowing forced sterilization. They asked that the Department affirm that State laws such as those do not provide a defense to a recipient who has otherwise violated this provision or any other part of section 504.

Response: The Department agrees that compliance with State law does not necessarily provide a defense to a recipient that has violated § 84.56 or any other part of section 504. With regard to the commenters who asked us to state that Federal laws always supersede State laws, including those that sanction forced sterilization, we note that section 504, as implemented in § 84.3, Relationship to Other Laws, applies standard principles of preemption. Any analysis of a conflict between § 84.56, the medical treatment section of this regulation, and State laws permitting sterilization will depend on an analysis of the specific State law. It is not therefore possible to make a blanket statement describing circumstances in which section 504 would preempt State law.

Examples of Discriminatory Treatment

Comments: Another example of discriminatory treatment offered by many disability rights organizations is the overprescribing of anti-psychotic medication to individuals with developmental disabilities for purposes of chemical restraint rather than because of a well-supported reason to believe the medication is likely to have a therapeutic effect on mental health. Other disability organizations offered the example of the inappropriate provision of involuntary mental health treatment as a potential instance of the discriminatory provision of treatment.

Some commenters offered as an example of a violation of § 84.56(b)(3) the use of aversive interventions, such as electric stimulation devices (ESD) for behavior modification. They noted that this intervention is not imposed on people without disabilities and would be considered illegal and unethical. Other commenters pointed to

[53] 42 U.S.C. 18116(a) (prohibiting discrimination on the basis of sex, among other grounds, in health programs or activities that receive Federal financial assistance, programs or activities administered by an Executive Agency or any entity established under title I of the Affordable Care Act).

unnecessary surgery being performed on people with disabilities.

Response: The Department agrees that the examples described above could constitute discriminatory provision of medical treatment under § 84.56(b)(3). For instance, the use of an intervention that seeks to modify behavior through the application of pain or other noxious stimuli, if not applied to people without disabilities, would likely violate § 84.56(b)(3), as it likely represents an instance of, on the basis of disability, providing medical treatment to an individual with a disability where a recipient would not provide the same treatment to an individual without a disability and where the disability does not impact the effectiveness, ease of administration, or have a medical effect on the condition to which the treatment is administered. As discussed elsewhere, the Department's investigations of specific complaints regarding violations of § 84.56 will be fact-dependent.

Informed Consent

Comments: Several commenters emphasized the importance of obtaining informed consent to any of these treatments, particularly those described above, from individuals with disabilities. They asked that we emphasize that consent procedures are always subject to a section 504 nondiscrimination analysis. Many said that requirements for informed consent could be improved if the reasonable modifications requirements are cross-referenced in this section.

Response: The Department notes that informed consent is essential. Cross-referencing the reasonable modification provision in particular sections is not necessary as it is a general requirement and already applies to all medical treatments and would apply to the informed consent process.

Individualized Judgment

Comments: Multiple commenters requested the Department specifically clarify that individualized judgment, rather than categorical judgments solely on the basis of a diagnosis, is necessary in evaluating whether a patient with a disability is qualified for a particular medical treatment. A request for clarifying the role of individualized judgment was made by both professional associations, which requested the Department ensure that clinical expertise and professional judgment was permitted to be used in individualized recommendations to patients, and organizations representing people with disabilities, which indicated that individualized judgment should be used in determining whether a person with a disability is not qualified for treatment.

Response: The Department agrees that it is important for providers to use individualized judgment when evaluating whether a person with a disability is qualified to receive a particular medical treatment and when communicating with people with disabilities about the implications of the different treatment options available to them. While we have not modified the regulatory text, we agree that individualized assessment will generally be required when evaluating whether a disability renders an individual not qualified for treatment or whether another legitimate nondiscriminatory reason exists to deny a particular treatment to a person with a disability. Categorical judgments based on the presence of a specific diagnosis that do not entail an individualized assessment may violate § 84.56.

However, recipients are nonetheless permitted to consider the standard of care and applicable medical evidence in forming their judgments of whether treatment is necessary or appropriate for individual patients. In the vast majority of circumstances, where medically indicated care depends on the specific clinical circumstances of the patient seeking treatment, recipients must engage in an individualized inquiry when determining eligibility for treatment. For example, a recipient that engages in a categorical judgment that all patients with a prior history of substance use disorders are not qualified to receive medications for pain management would likely discriminate against persons with a record of a substance use disorder under § 84.56(b)(1)(i) if their denial with respect to a specific patient was based on such a categorical judgment rather than individualized assessment of the specific patient seeking pain management. Such a categorical judgment would not be protected under the professional judgment in treatment provision in § 84.56(c).

Other Issues Raised by Commenters

Comment: Some commenters asked the Department to carefully review the regulatory text to ensure that the language was as clear as possible to a broader audience.

Response: In response to this feedback, the Department has made non-substantive edits to § 84.56(c)(1)(ii) to improve clarity of language. Revised paragraph (c)(1)(ii) provides circumstances when medical treatment is not required, including when a recipient has a legitimate, nondiscriminatory reason for denying or limiting service or where the disability renders the individual not qualified for the treatment. We do not believe this changes the substantive meaning of the section from the NPRM, but have made the change in order to improve clarity of language.

Comment: Some commenters asked the Department to clarify that the criteria in § 84.56(b)(1)(i) through (iii) are not an exhaustive list of the circumstances that would be considered discriminatory reasons for denying or limiting medical treatment or determining that an individual is not qualified for treatment.

Response: As the Department previously indicated within the NPRM, the list of criteria in § 84.56(b)(1)(i) through (iii) is not an exhaustive list.

Comment: One provider group asked the Department to indicate whether the decision to place a feeding tube in an individual with advanced dementia instead of hand feeding could include considering the individual's prognosis and whether the potential benefit of a feeding tube outweighs the harms.

Response: Whether providing or denying any type of medical treatment to patients with disabilities when the provider would not do the same for patients without disabilities is discriminatory depends on the facts and context of the specific case and is beyond the ability of the Department to address in the abstract. Factors that may be relevant in the feeding tube decision, include: the wishes of a patient or their authorized representative, the inability of a patient to express their preference in the absence of an authorized representative, and a recipient's choice to avoid the use of physical restraints and/or the denial of the gratification of tasting preferred foods. In contrast, should the recipient opt to decline to place a feeding tube because they believe that continued life would not be of benefit to the patient with advanced dementia, this could violate § 84.56(b)(1)(iii) and (b)(2).

Comment: A commenter expressed concern with language under § 84.56(c)(1)(ii) indicating that a recipient is not obligated to provide a service if the recipient reasonably determines based on current medical knowledge or the best available objective evidence that such medical treatment is not clinically appropriate for a particular individual. They express concern that the phrase ''best available objective evidence'' may be too subjective, as ''even experts may differ on the exact rank of certain information in a clinical evidence hierarchy or even

on the hierarchy itself.'' They ask that the Department modify this language to instead indicate that ''a preponderance of evidence support the determination regarding what is or is not clinically appropriate.''

Response: After consideration, the Department has elected to maintain the current regulatory text. While experts may differ on the relative strength of clinical evidence, it is incumbent upon each recipient to make use of the best available objective evidence within the context of their discipline, recognizing that in many instances a mixed clinical literature will result in different clinicians arriving at different decisions. Differences among experts or between studies may be relevant to whether a particular medical treatment decision is discriminatory. In such instances, the Department will consider whether a recipient's actions are consistent with the existing evidence base.

Comment: A medical organization requested that the Department clarify that if the clinical literature shows that the therapy is less effective for individuals with a characteristic or marker associated with a certain disability and as a result is not recommended for such individuals under clinical guidelines, it would not be discriminatory to limit coverage to those individuals who do not have the characteristic or marker.

Response: Information on efficacy and effectiveness in the clinical literature is relevant in assessing whether the provision of a drug or decision not to provide to a person with a disability is discriminatory. The specific application of § 84.56 may depend on a variety of factors, such as the relative strength of the evidence in the clinical literature, whether the evidence indicates a drug is ineffective for a particular subpopulation of patients with disabilities or merely less effective, and the standards the recipient applies for the provision of medical treatment to patients without the disability in question.

Comments: Several commenters asked the Department to modify § 84.56(c)(1)(ii) to clarify that the criteria in § 84.56(b)(1)(i) through (iii) may not be used as the basis for determining that an alternative course of treatment would be more likely to be successful.

Response: The Department has indicated that the criteria in § 84.56(b)(1)(i) through (iii) may not be used to determine that a treatment is not clinically appropriate for a particular individual. The determination of clinical appropriateness includes whether a treatment would be more likely to be successful than other treatments, and thus the circumstances described by the commenters is already incorporated in the existing text. We have elected not to modify the regulatory text.

Delays in Care Due to Difficulty in Locating an Interpreter

Comment: One commenter specifically asked the Department to clarify that delays or rescheduling of care due to a recipient's inability to locate a Certified Deaf Interpreter would not constitute a violation of § 84.56.

Response: The Department cannot provide categorical responses to issues that are dependent on facts. Relevant facts may include whether the patient's medical care is promptly rescheduled, the impact of the delay on the patient's receipt of effective medical care, whether the recipient's methods of administration (including rate of pay to interpreters) may be causing an unnecessary delay in accessing a Certified Deaf Interpreter, and whether the patient has received the option of receiving care using another means of effective communication that meets their needs.

Comment: A commenter requested that the Department replace the phrase ''where the disability renders the individual not qualified for treatment'' with the phrase ''when a patient's disability may pose a legitimate medical contraindication for the treatment under consideration.''

Response: The reference to whether a person with a disability is ''qualified'' for treatment reflects the statutory language of section 504. As a result, we will maintain the regulatory text as proposed.

Comments: Several commenters asked the Department to clarify that recipients may not mischaracterize the services that they ordinarily provide in their scope of practice to evade anti-discrimination protections. A commenter also asked us to clarify that a recipient may be required to provide a service that it does not ordinarily offer as a reasonable modification for a qualified individual with a disability.

Response: The Department agrees that recipients may not manipulate their scope of practice as a pretext for discrimination against people with disabilities. For example, recipients may not define their scope of practice to preclude the provision of medical treatment offered to other patients to patients with disabilities. For example, an OB–GYN who indicates that their scope of practice excludes the provision of mammograms to women with Down syndrome, as they do not have requisite expertise in developmental disability, would likely be in violation of § 84.56. In addition, the OB–GYN may be obligated to make reasonable modifications consistent with § 84.68(b)(7) for a patient with Down syndrome in order to make a mammogram accessible, including providing additional time to explain the procedure, manage sensory sensitivities, or communicate with a designated supporter for purposes of supported decision-making.

Similarly, recipients who define their scope of practice to exclude the provision of medical services associated with a specific disability that are typically offered by comparable colleagues may be in violation of § 84.56. For example, a pharmacist who indicates that the filling of prescriptions for antiretroviral therapy for patients with HIV is outside their scope of practice when similar pharmacies do fill such prescriptions and there is no nondiscriminatory rationale for why filling such prescriptions would be outside their area of expertise and ability would likely be in violation of § 84.56.

Consent

Comments: Commenters asked the Department to provide additional examples regarding how discussions about limiting treatment would and would not be consistent with § 84.56(c)(3). One commenter specifically raised older adults with multiple chronic conditions who are on multiple drugs, some of which may interact in ways that harm the person, noting that review of the patient's medications will often result in discontinuation of certain drugs and/or changing drugs in order to cause less harm. Another commenter raised an example under which a child is born with genetic condition resulting in cognitive impairment and a provider erroneously informs the family that patients with that condition never live to adulthood in order to convince them to withhold life-sustaining treatment, motivated by a belief that persons with cognitive impairment constitute a burden to others.

Response: Section 84.56(c)(3) addresses the information exchange between the recipient and the patient with a disability concerning potential courses of treatment and their implications, including the option of forgoing treatment. This provision indicates that nothing in this section precludes a provider from providing an individual with a disability or their authorized representative with information on the implications of different courses of treatment based on

current medical knowledge or the best available objective evidence. The Department interprets this as including the provider's own experiences with treatment options for any particular medical intervention. The ability of a person with a disability or their authorized representative to understand the available options and to make an informed decision about the medical treatment depends in part on the expertise and candor of the treating professionals. However, the Department intends that the result of reading § 84.56(a) and (c)(2)(ii) together is that the recipient is prohibited from discriminating on the basis of disability in seeking consent for the decision to treat or to forgo treatment by, for example, unduly pressuring a person with a disability or their authorized representative to conform to the treating professional's position or by relying on the prohibited factors listed in § 84.56(b)(1)(i) through (iii). Consistent with the request of the commenters, we offer several illustrative examples below of circumstances where a recipient would likely be in compliance with or in violation of § 84.56, taking into account § 84.56(c)(3) and its interaction with § 84.56(c)(2)(ii).

A person with Type II Diabetes is diagnosed with Chronic Obstructive Pulmonary Disease. Their physician notes that medications for each of these conditions frequently interact, and discusses with the patient the need to change the drugs they are currently taking or offer different drugs than would typically be provided for their new diagnosis, in order to avoid unintended side effects or other complications from drug interactions. Such discussion is generally consistent with § 84.56(c)(3). Similarly, discontinuing, changing, or offering different medications to such a patient in order to address side effects or complications from drug interactions would generally not present any conflict with other parts of § 84.56.

A person with advanced dementia is diagnosed with cancer. Their physician reviews their expected prognosis and concludes that chemotherapy would only extend their life for a brief period and would come with significant unpleasant side effects. They discuss with the patient or their authorized representative the implications of different courses of treatment, including whether treating the cancer is inconsistent with their preferences in light of anticipated complications. This is generally consistent with § 84.56(c)(3). In addition, the physician informing the patient of anticipated side effects from treatment and the patient choosing to decline further life-sustaining treatment based on the patient's belief that extending their life would not be of benefit to them is generally not in violation of § 84.56(c)(2)(ii).

In contrast, when a physician pressures the patient or their authorized representative to choose to decline life-sustaining treatment as a result of the patient's disability, such behavior is likely inconsistent with § 84.56(c)(2)(ii). If this is motivated by a belief that life with the patient's disability is not worth living or a belief that the patient's medical costs will be a burden on society, this would likely be a violation of § 84.56(b)(1).

Comments: Many organizations representing individuals with disabilities commented on § 84.56(c)(3). Some commenters noted that, as written, the paragraph focuses on the actions of the recipient when it says that nothing prohibits a recipient from providing information about all treatment options. One commenter suggested that the paragraph be rewritten to focus on the right of individuals with disabilities to obtain complete information about treatment options. Almost all of the comments received by the Department discussed this right of individuals with disabilities to obtain complete information about treatment options.

A significant number of commenters said that without an open and candid discussion of all options, an individual is not able to give informed consent to treatments. Many noted that sometimes all options are not discussed because the provider has made assumptions about which options they think are best and, accordingly, they only provide information about those options. A professional medical organization stressed the importance of making patients aware of all possible options including risks and potential complications. After making individuals aware of all possible options and the risks associated with each, the provider and the individual with disabilities should jointly come to a decision about which course of treatment will yield the best outcome. Another organization said that it is crucial that the provider be aware of what matters most to patients; patients deserve to know whether a treatment provides clear and important benefits and is aligned with their care preferences.

Commenters were broadly in agreement about the importance of permitting reasonable modifications that will enable an individual with disabilities to understand and indicate consent or disagreement with what is being discussed, including allowing a supporter to help the individual make reasoned decisions in an accessible way through supported decision-making. Some commenters mentioned the importance of using plain, accessible language and, when not urgent, giving the individual time to discuss and think about the options without pressure. Sometimes a more in-depth discussion may be required than would be given to an individual without a disability and some mentioned that longer discussions may require breaks.

Many people with disabilities discussed experiencing discrimination as a result of their use of or request for reasonable modifications, including the use of accessible telehealth and medical devices, access to certified interpreters for the Deaf, the use of Augmentative and Alternative Communication (AAC) technology, the use of supported decision-making, and other reasonable modifications as well as auxiliary aids and services.

Response: We appreciate the commenters' feedback. This provision, when read in conjunction with the remainder of the section, focuses not only on what information a recipient can provide but also on what the provider must provide. We agree with commenters who stressed the importance of providing all treatment options to individuals with disabilities.

The failure to offer information about all options could be a result of the provider's own assumptions about which option is the best. When providers do not offer complete information because they have made an assumption based on bias, a judgment that an individual with a disability will be a burden on others, or that an individual with disability's life has a lesser value than that of an individual without a disability, they have likely violated § 84.56(b)(1). Such withholding of information in order to obtain consent to decline treatment would also likely violate § 84.56(c)(2)(ii), as would the withholding of information on the basis of disability for other rationales.

Section 84.68(b)(7) requires recipients to make reasonable modifications to policies, practices, and procedures when necessary to avoid discrimination unless the recipient can demonstrate that making the modifications would result in a fundamental alteration in the program or activity. Multiple commenters requested that we discuss supported decision-making in the medical treatment section and not just in the reasonable modifications section. We are including this discussion here, as requested, because the importance of permitting supported decision-makers

to allow individuals with disabilities the means to make an informed decision about the best course of treatment is relevant to § 84.56(c)(2) as well as § 84.68(b)(7). Permitting individuals with disabilities to have a supported decision-maker with them to help facilitate effective communication and/or to help them decide on the best course of treatment can be crucial in ensuring that individuals with disabilities are able to give informed consent to medical treatments. Allowing a supported decision-maker may require other reasonable modifications such as changing visitor policies. More detailed information about supported decision-making as a reasonable modification can be found in the preamble to § 84.68(b)(7).

We also agree with commenters' suggestions of other types of reasonable modifications and other forms of effective communication that might be required, for example, by putting certain materials in plain language, presenting information in a way that it can be understood, permitting people with disabilities to bring a trusted friend or family member into discussions as a supporter, and allowing breaks in long discussions.

Comments: In light of the clarification under § 84.56(c)(2)(i) that nothing in this section requires a recipient to provide medical treatment to an individual where the individual, or their authorized representative, does not consent to that treatment, some commenters sought additional clarification on the scope of authority of an authorized representative, in particular whether recipients may have an obligation to seek additional clarification or review of those decisions when they would do so for a similarly situated patient without a disability. One commenter asked the Department to clarify that nothing in the regulation should preclude Federal or State law from limiting the power of an authorized representative, including a parent, to refuse life sustaining care for an individual.

Response: With respect to distinguishing between decisions made by a patient's legally authorized representative and decisions made by the patient themselves or distinguishing between authorized representatives designated by the patient and those that were not so designated, recipient obligations are generally to not treat patients with disabilities differently from patients without disabilities in this regard. For instance, if recipients would seek additional clarification or ethics review in response to a request from an authorized representative to decline life-sustaining or otherwise medically indicated treatment to a person without a specific disability, then they are generally obligated to undertake the same steps for a similarly situated person with a disability under § 84.56. In contrast, if they would not seek additional clarification or review when a proxy made such a decision for a person without a disability, § 84.56 does not generally require them to do so for a person with a disability. Although some forms of authorized representation, such as guardianship or conservatorship, are typically applied only to people with disabilities, multiple comparators exist for authorized representatives that are also applied to people without disabilities. For example, patients without disabilities often designate medical proxies or powers of attorney for health care decision-making. Similarly, parents often make decisions on behalf of minor children with and without disabilities. These may allow for an appropriate comparison for the treatment of proxy decision-making, including under circumstances where the expressed wishes of the patient seem to differ from that of the proxy or where the treatment decision in question is medically contraindicated.

In general, the Department agrees that the regulation does not preclude Federal or State law from limiting the power of an authorized representative, including with respect to decisions regarding refusing life-sustaining care. As noted previously in the preamble, section 504, as implemented in § 84.3, Relationship to other laws, applies standard principles of preemption.

Comment: A commenter requested the Department clarify that informed decision-making may appropriately result in patients electing hospice care.

Response: The Department agrees with the commenter that informed decision-making may appropriately result in patients electing a wide array of services and care, including hospice care. Such decision-making on the part of the patient is generally not a violation of § 84.56.

Comment: A commenter representing educators for the deaf indicated that some children's hospitals have a practice of requiring parents or guardians of deaf and hard of hearing children to commit during the evaluation process for a cochlear implant that they will not use sign language nor enroll their children in schools for the deaf, even if they currently use sign language and are enrolled at schools for the deaf at present. While they agree that the determination of clinical eligibility for a cochlear implant is best left to surgeons, they ask the Department to clarify that this would constitute prohibited discrimination under § 84.56 if patients are denied access to medically indicated treatment due to their refusal to commit to such terms.

Response: As indicated elsewhere, discrimination against patients with disabilities due to their use of a particular treatment or service associated with their disability can constitute discrimination on the basis of disability. As a determination that discrimination has occurred is generally fact-specific, the Department would need to review the facts of a specific case to evaluate this question. However, we agree that a categorical requirement that patients with disabilities will be denied access to (or be led to believe they will be denied access to) medically indicated treatment if they do not commit to avoid use of assistive technology, reasonable modifications, or educational interventions associated with their disability could constitute a violation of § 84.56 if such a requirement was not medically indicated in order to receive the sought after treatment.

Comment: One commenter asked the Department to clarify that delays due to the engagement of an authorized representative would not constitute a violation of § 84.56. They describe a situation where a patient requires informed consent from an authorized representative to receive care, but the health care provider cannot reach the authorized representative to get informed consent in a timely manner.

Response: The Department agrees that delays due to the engagement of an authorized representative would generally not constitute a violation of § 84.56, provided that the patient requires a representative in order to provide informed consent and that this judgment is not made based on a categorical belief that all patients with a specific kind of disability (*e.g.,* serious mental illness or a cognitive disability) require a representative in order to provide informed consent. We also note that there are circumstances where physicians would typically not wait for an authorized representative to make decisions for persons without disabilities who cannot provide informed consent (*e.g.,* minor children or patients who are incapacitated on a short-term basis without a disability), such as for the provision of immediately required life-saving or life-sustaining treatment. Under such circumstances, the recipient must generally treat the patient with a disability with no more delay than they would apply to a

similarly situated patient without a disability.

Comments: Multiple commenters asked the Department to speak to the intersection of disability with other types of discrimination.

Response: The Department acknowledges that disability discrimination frequently co-occurs with other types of discrimination and that the result of these different forms of discrimination can intersect, resulting in discrimination that is unique to the intersection of bases of discrimination. Section 504 prohibits discrimination on the basis of disability and, in addition to disability discrimination, OCR has been delegated authority under laws that prohibit discrimination on the basis of race, color, national origin, sex, and age. The Department agrees that simultaneous discrimination on multiple prohibited bases (including but not limited to intersectional discrimination) is important to account for. Section 1557, which OCR enforces, prohibits such simultaneous discrimination.

We continue to consider effective ways to address these issues within the existing statutory authorities delegated to OCR. For instance, OCR's proposed rulemaking on section 1557 would require covered entities to comply with uniform policies and procedures that apply across all prohibited bases of discrimination, rather than different procedural requirements depending on the alleged basis of discrimination. This accounts for claims of discrimination that are alleged to have occurred based on multiple protected bases discrimination and provides for more consistency regardless of whether an allegation of discrimination is based on race, color, national origin, sex, age, or disability—or some combination thereof.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.56 as proposed with one modification. We are changing § 84.56(c)(1)(ii) so that the first sentence provides that circumstances in which the recipient has a legitimate, nondiscriminatory reason for denying or limiting a service or where the disability renders the individual not qualified for the treatment may include circumstances in which the recipient typically declines to provide the treatment to any individual, or reasonably determines based on current medical knowledge or the best available objective evidence that such medical treatment is not clinically appropriate for a particular individual.

Value Assessment (§ 84.57)

Proposed § 84.57 addressed the application of section 504 to value assessment. It stated that a recipient may not use any measure, assessment, or tool that discounts the value of life extension on the basis of disability to deny or afford an unequal opportunity to qualified individuals with disabilities with respect to any aid, benefit, or service, including the terms or conditions under which they are made.

The Department sought comment on how value assessment tools and methods may provide unequal opportunities to individuals with disabilities and on other types of disability discrimination in value assessment not already specifically addressed with the proposed rulemaking. We also sought comment on whether the provision would have a chilling effect on academic research.

The comments and our responses regarding § 84.57 are set forth below.

Comment: Many commenters, including entities engaged in value assessment, expressed broad support for the Department's proposal to include a provision relating to disability discrimination in value assessment. One comment from a prominent organization engaged in value assessment activities referred to the Department's proposed regulatory text as ''very precise and appropriate'' and indicated support for the provision in its current form.

Response: The Department appreciates comments on our proposed approach to addressing disability discrimination in value assessment, including comments that the proposed rule appropriately prohibits discriminatory uses of value assessment and permits the use of value assessment in a nondiscriminatory fashion.

Comment: Many commenters asked the Department to consider expanding the scope of § 84.57 to prohibit discounting the value of quality of life, in addition to life extension, on the basis of disability. Other commenters specifically asked the Department not to expand the provision in this way and requested the Department maintain the regulatory text proposed within the NPRM.

Response: While the Department has addressed disability discrimination on the basis of perceptions of quality of life in other aspects of the regulation, § 84.57 applies only to value assessment methods that discount the value of life extension on the basis of disability. As discussed in the NPRM, elements of value assessment methods that may violate § 84.57 in some contexts—such as for valuing life extension—may not violate it in other contexts. We have decided against adding a prohibition on measures that discount the value of quality of life on the basis of disability in § 84.57 because, within the context of value assessment, the use of measures that determine the value of a treatment based on the magnitude of quality of life changes are often beneficial to persons with disabilities. Such measures create a mechanism through which the relative degree of quality of life improvements a treatment provides compared to other similar treatments can be incorporated into a pricing strategy. However, we reiterate that the use of measures that also discount the value of life-extension on the basis of disability to deny or afford an unequal opportunity to qualified individuals with disabilities with respect to any aid, benefit, or service, including the terms or conditions under which they are made available, would be prohibited. This remains the case even if the additional value assigned to a treatment due to quality of life improvements fully offsets any penalty assigned from discounting the value of life-extension. We also note that discounting the value of quality of life on the basis of disability for purposes of denying or limiting medical treatment to a qualified individual with a disability would likely violate § 84.56.

Other aspects of this rule may also be relevant when evaluating recipient value assessment activities. These include § 84.56, which prohibits discrimination on the basis of biases or stereotypes about a patient's disability, judgments that the individual will be a burden on others due to their disability, and a belief that the life of a person with a disability has lesser value or that life with a disability is not worth living. The Department will continue to monitor disability discrimination concerns in value assessment activities as the field develops.

Comment: Some commenters requested that the Department specifically clarify that the Department does not intend to prohibit nondiscriminatory uses of value assessment.

Response: As indicated in the NPRM, the rule does not prohibit nondiscriminatory uses of value assessment.

Comment: Many commenters asked the Department to indicate that certain specific methods of value assessment were permitted under § 84.57, while other commenters asked the Department to indicate that the same or similar methods were prohibited under § 84.57.

Response: As the Department indicated within the NPRM, we have

elected not to identify the use of any specific method of value assessment, but instead to prohibit measures that discount the value of life extension on the basis of disability when used to deny or provide an unequal opportunity for a qualified person with a disability to participate in or benefit from an aid, benefit, or service. We have done so because the determination that a specific value assessment method will be prohibited depends on the specific context and purpose for which that method is utilized. For example, some methods that are impermissible for purposes of reimbursement or utilization management decisions are still permitted for purposes of academic research.

The use of a measure that does not discount the value of life extension on the basis of disability likely does not violate § 84.57. The Department notes, however, that composite measures that use methods that discount the value of life extension on the basis of disability as one component of a larger summary measure or pricing strategy could, depending on the particular facts of a specific case, be prohibited for use in determining eligibility or referral for, or provision or withdrawal of any aid, benefit, or service, including the terms or conditions under which they are made available if the component that discounts the value of life extension contributes to the price set by the measure or any decision to determine eligibility, referral for, or provision or withdrawal of an aid, benefit or service. This is true even where other components of the summary measure or pricing strategy do not discount the value of life extension.

Comment: A commenter requested the Department prohibit all ''cost-per-generic-health metric'' methods of value assessment, encompassing a broad range of methodologies not prohibited under the current language of § 84.57.

Response: The Department declines to make this change. A prohibition as broad as the one proposed by the commenter would encompass alternative methods of value assessment that do not discriminate on the basis of disability under the Department's current understanding of section 504. We have elected to limit § 84.57 to measures that discount the value of life extension on the basis of disability when used to deny or provide an unequal opportunity for a qualified person with a disability to participate in or benefit from an aid, benefit, or service.

Comment: Some commenters asked the Department to align the language of § 84.57 with the text of section 1182 of the Affordable Care Act, which prohibits ''the use of a dollars-per-quality-adjusted-life-year (or similar measure that discounts the value of a life because of an individual's disability)'' from being used to determine coverage, reimbursement, or incentive programs in certain program or activities.

Response: The Department has elected not to modify the regulatory text. The Department interprets recipient obligations under the current language of § 84.57 to be broader than section 1182 of the Affordable Care Act, because it prohibits practices prohibited by section 1182 (where they are used to deny or afford an unequal opportunity to qualified individuals with disabilities with respect to the eligibility or referral for, or provision or withdrawal of an aid, benefit, or service) and prohibits other instances of discriminatory value assessment. As we have indicated elsewhere, section 504 is a civil rights statute rather than a program statute, and thus is not required to align precisely with requirements in program statutes. We decline to modify the regulatory text to use the same language as in section 1182.

Comment: Some commenters asked the Department to clarify that a recipient engaged in value assessment activities that is in compliance with § 84.57 might still violate other requirements under section 504 in such activities. For example, one State Attorney General asked the Department to explicitly indicate that § 84.57 is not exclusive and does not preclude the application of other provisions of section 504 to value assessment activities. In the absence of such clarification from the Department, the commenter raised concerns that § 84.57 might inadvertently foreclose claims against recipients who use discriminatory algorithms or artificial intelligence tools that discriminate against people with disabilities.

Response: The Department agrees that compliance with § 84.57—which prohibits only the use of value assessment methods that discount the value of life extension on the basis of disability to deny or afford an unequal opportunity to qualified individuals with disabilities with respect to the eligibility or referral for, or provision or withdrawal of any aid, benefit, or service—does not mean that a recipient has not violated other provisions of the section 504 rule.

Comment: Several commenters asked the Department to indicate whether the use of specific value assessment methods to develop health care policies, including drug formularies and utilization management strategies, could be discriminatory under § 84.57.

Response: The use of value assessment methods for developing health care policies, including drug formularies and utilization management strategies, could be discriminatory under § 84.57 if the method used discounts the value of life extension on the basis of disability and is used to determine eligibility or referral for, or provision or withdrawal of any aid, benefit, or service. This could include, for example, the use of value assessment methods for formulary construction, design, development, or refinement as well as other utilization management strategies of recipients.

Comment: Several comments asked the Department to provide additional clarity on the application of § 84.57 to academic research. One commentor asked the Department to specifically clarify that academic research, including research that references quality-adjusted life years (QALYs), can be used to inform multi-factor Medicaid agency decision making. Other commenters asked the Department to provide additional clarity with respect to how academic research may be used for purposes of value assessment.

Response: Within the NPRM, the Department explicitly indicated that it is the discriminatory use of a measure by a recipient that violates of § 84.57. The use of a methodology that is discriminatory when applied to determine eligibility, referral for, or provision or withdrawal of an aid, benefit, or service would not be discriminatory if used in academic research to assess the relative effect of different policy changes or medical innovations on national or global population health.

However, a recipient who makes use of academic research to determine eligibility, referral for, or provision or withdrawal of an aid, benefit, or service may violate section 504 if the use of the method in the research product is discriminatory when applied in the new context. A value assessment output used by a recipient that is derived from a method that discounts the value of life extension on the basis of disability is not made permissible because the recipient is using a research product, when it would not be permissible for the recipient to make use of that method directly.

As to the use of academic research in Medicaid agency decision-making, as discussed in the NPRM, the Department does not intend to reference any further specific value assessment methods as prohibited or permitted under § 84.57, as this determination will be the result

of the specific context and purpose for which a value assessment method is utilized. However, recipients may make use of prices or other outputs from value assessment methods that do not discount the value of life-extension on the basis of disability within academic research. This remains the case even where that academic research also includes prices or other outputs determined via methods that do discount the value of life extension on the basis of disability, provided that the recipient is only making use of outputs that come from value assessment methods that do not discount the value of life extension on the basis of disability.

For example, consider a State Medicaid agency seeking to determine appropriate pricing for a new drug for purposes of negotiating drug prices with a manufacturer and subsequently making decisions regarding utilization management. In doing so, they refer to academic research that calculates multiple potential pricing options for that drug, using multiple different value assessment methods for purposes of comparing pricing under different methods. Some of these methods discount the value of life extension on the basis of disability, whereas others do not. The State Medicaid agency would generally not violate § 84.57 if it uses pricing from methods that do not discount the value of life extension on the basis of disability to inform their negotiations with a manufacturer. In contrast, should the State Medicaid agency use prices or other outputs from a value assessment method that does discount the value of life extension on the basis of disability presented within the same academic research, this could violate § 84.57.

Comment: One commenter expressed concern that the Department's explanation of § 84.57 in the NPRM was inconsistent with language in § 84.56(b)(2) prohibiting discrimination only in instances where an individual experiences discrimination on the basis of an underlying disability distinct from the separately diagnosable symptom or medical condition they are seeking treatment from. They asked the Department to clarify its discussion of § 84.57 to align it with § 84.56(b)(2).

Response: This comment misunderstands the scope of section 504 and the referenced provisions. These are different provisions with different applications. The distinction between persons seeking treatment for their own underlying disability and persons seeking treatment for a separately diagnosable symptom or medical condition is made only with respect to the broad-based prohibition in § 84.56(b)(2) indicating that a recipient may not deny or limit clinically appropriate treatment if it would be offered to a similarly situated individual without an underlying disability. The medical treatment provision is not limited to that one part.

For example, even within § 84.56, the Department indicates that discrimination based on biases or stereotypes about a patient's disability, judgments that the individual will be a burden on others due to their disability, or a belief that the life of a person with a disability has lesser value or that life with a disability is not worth living is prohibited regardless of whether treatment is sought for a separately diagnosable medical condition or symptom or for a patient's underlying disability. These obligations apply to recipient activities without regard to whether the potential discrimination in the use of a value assessment method is on the basis of an underlying disability or separately diagnosable symptom or medical condition. Similarly, other provisions implementing section 504—such as § 84.57—are also not subject to this limitation.

Comment: One commenter argued that the use of the QALYs and other methods of value assessment that frequently entail discounting the value of life extension on the basis of disability are not discriminatory because they are ''only one step'' in a process of decision-making, noting that policymakers also take into account other factors in their ultimate decision-making.

Response: Although recipients may make use of multiple factors to influence their decision-making, the use of a measure of value that assigns lower value to extending the lives of people with disabilities to determine eligibility, referral, or provision or withdrawal of an aid, benefit, or service can be nonetheless discriminatory.

Comment: One commenter requested that the Department not take a stance on utility weight generation. They specifically asked that we not require the use of direct patient utilities. They noted that concerns that value assessment ''quantifies stereotypic assumptions about persons with disabilities'' relate ''less to the application of cost-per-QALY analyses, and more to the underlying elicitation approach used to generate utility weights called time-trade-off exercises.'' The commenter argued that there is value in ''both general population preferences and patient preferences'' in generating utility weights and that relying exclusively on patient preferences might serve to undervalue treatments as compared to using utility weights from the general population.

Response: The Department agrees that it would not be appropriate to require the use of direct patient utilities. Methods of utility weight generation are subject to section 504 when they are used in a way that discriminates. They are subject to § 84.57 and other provisions within the rule, such as § 84.56's prohibition of discrimination based on biases or stereotypes about a patient's disability, among others. However, the Department does not take a position on specific methods of utility weight generation at this time.

Comment: One commenter asked the Department to modify the language reading ''value of life extension'' to ''value of treatments that extend life.'' They indicate that this would better reflect their view that ''the objective of value assessment is not to value the life of individuals, rather, estimate the value of treatments that may extend life.''

Response: We decline to make this change, as the proposed text ''value of treatments that extend life'' would substantially alter the meaning of the regulation, prohibiting a far broader scope of value assessment activities than the current text. Furthermore, we believe that the current language accurately describes the discriminatory uses of value assessment prohibited by this provision.

Comment: One commenter asked the Department to avoid banning the QALY in academic research, expressing concern for unintended consequences of such a step.

Response: Section 84.57 does not prohibit the use of any value assessment method, including the QALY, in academic research. As mentioned in the NPRM, the use of a methodology that is discriminatory when applied to determine eligibility, referral for, or provision or withdrawal of an aid, benefit, or service would not be discriminatory if used in academic research to assess the relative contribution of different policy changes or medical innovations on national or global population health. In addition, we reiterate that the discriminatory use of a measure by a recipient violates this provision, but other uses may not. Nor does the rule outright ban the use of specific measures such as QALYs.

Comment: Some commenters argued that the use of the QALY and other similar measures that discount the value of life extension on the basis of disability for purposes of resource allocation is not discriminatory because it yields a higher valuation for a given health care intervention than a cost-per-

life-year calculation would, as the latter does not take into account quality of life improvements. They also reference other value assessment methods that may, under certain circumstances, assign lower valuations than a cost-per-QALY framework. The commenters argue that because the QALY delivers a higher valuation than non-QALY methods under these circumstances it cannot be discriminatory to make use of it even where it discounts the value of life-extension on the basis of disability, as it assigns a higher valuation to quality of life improvements than the alternative methods they reference.

Response: The Department disagrees. It is true that for interventions that improve quality of life, a cost-per-QALY valuation will likely be higher than a cost-per-life-year valuation, because a cost-per-life-year approach assigns no value to quality of life improvements. We note the availability of other value assessment methods. However, compliance with § 84.57 does not require the use of a cost-per-life-year valuation, an approach that is relatively uncommon when evaluating interventions that improve patient quality of life. The use of other alternative value assessment methods may yield different results.

In addition, the discriminatory nature of assigning less value to extending the lives of people with disabilities remains the case even where other factors in a value assessment system result in a higher valuation. In short, discounting the value of life-extension on the basis of disability to deny or afford an unequal opportunity to qualified individuals with disabilities is prohibited even if other aspects of a system of value assessment favor people with disabilities (though a recipient could incorporate such favorable treatment into an approach that does not discount life-extension on the basis of disability for such purposes). Favorable treatment in one component of a program of value assessment does not permit discriminatory treatment in another context. Finally, we note that the Department does not take a position on which alternative measure of value assessment recipients should use.

Comment: The Department requested comment on how value assessment tools and methods may provide unequal opportunities to individuals with disabilities. Numerous commenters indicated that value assessment methods could limit people with disabilities' access to health care goods and services, including pharmaceutical interventions, and expressed concern that the use of the QALY unfairly limited access to emerging pharmaceutical interventions that could extend the lives of people with disabilities.

Response: While the nondiscriminatory use of value assessment is an important tool for health care cost containment, the Department agrees that discriminatory usages of value assessment harm people with disabilities and provide unequal opportunities.

Comment: The Department requested comment on other types of disability discrimination in value assessment not already specifically addressed within the proposed rulemaking. In addition to the proposals already discussed, some commenters urged the Department to consider disability discrimination in clinical algorithms, automated decision-making and artificial intelligence. This was also raised in comments regarding § 84.56.

Response: The Department agrees that disability discrimination resulting from the use of algorithms, automated decision-making, and artificial intelligence is a serious issue. Section 504 prohibits a recipient from discriminating on the basis of disability. This encompasses discrimination through a recipient's use of algorithms, automated decision-making, and artificial intelligence. For example, during the COVID–19 public health emergency, OCR discovered that Crisis Standards of Care plans that States and hospital systems used to allocate scarce resources relied on clinical algorithms to determine the allocation of scarce critical care resources. Many of these algorithms discriminated against people with disabilities and older individuals by categorically excluding patients with certain types of disabilities or by considering other factors that can be discriminatory based on disability or age, such as long-term survival prospects or anticipated intensity of resource utilization. OCR worked extensively with several States during the public health emergency to help them revise their Crisis Standards of Care plans to remove discriminatory bias [54] and issued guidance on that issue.[55] We note that other Federal agencies have also identified that disability discrimination through the use of algorithms and artificial intelligence violates existing Federal civil rights laws.[56] The Department is particularly interested in monitoring disability discrimination through the use of these tools in the context of child welfare, medical treatment, long-term services and supports, and alternative payment models. Section 504 already prohibits disability discrimination in these and other activities through recipients' use of clinical algorithms, automated decision-making, and artificial intelligence. A more tailored application of the framework outlined here to algorithms, automated decision-making, and artificial intelligence requires further information gathering.

As we discussed earlier in the preamble, §§ 84.56 and 84.57 are not exhaustive with respect to recipient obligations regarding medical treatment and value assessment, respectively. A recipient's compliance with §§ 84.56 and 84.57 does not preclude liability for violations of other sections.

OCR has taken additional and will consider further actions to clarify recipients' obligations under Federal civil rights laws regarding the use of algorithms, automated decision-making, and artificial intelligence. For example, the Department's section 1557 final rule on Nondiscrimination in Health Programs and Activities prohibits a covered entity from discriminating on the basis of race, color, national origin, sex, age, or disability in its health programs or activities through the use of patient care decision support tools, which include algorithms, automated and non-automated tools, and artificial intelligence used to support clinical decision-making.

The Department is interested in the public's views regarding disability discrimination that occurs through the use of algorithms, automated decision-making, and artificial intelligence. We are also interested in the public's views on whether OCR should issue guidance

[54] U.S. Dep't of Health & Human Servs., Off. for Civil Rts., Civil Rights and COVID–19, *https://www.hhs.gov/civil-rights/for-providers/civil-rights-covid19/index.html#:~:text=NON%2DDISCRIMINATION%20IN%20CRISIS%20STANDARDS%20OF%20CARE* (last reviewed May 11, 2023).

[55] U.S. Dep't of Health & Human Servs., Off. for Civil Rts., FAQs for Healthcare Providers During the COVID–19 Public Health Emergency: Federal Civil Rights Protections for Individuals with Disabilities under Section 504 and Section 1557, *https://www.hhs.gov/civil-rights/for-providers/civil-rights-covid19/disabilty-faqs/index.html#footnote3_2brd1au;* Press release, Dep't of Health & Human Servs., Off. for Civil Rts., HHS Issues New Guidance for Health Care Providers on Civil Rights Protections for People with Disabilities (Feb. 4, 2022), *https://www.hhs.gov/about/news/2022/02/04/hhs-issues-new-guidance-health-care-providers-civil-rights-protections-people-disabilities.html.*

[56] *See, e.g.,* U.S. Dep't of Justice, Algorithms, Artificial Intelligence, and Disability Discrimination in Hiring (2022), *https://www.ada.gov/resources/ai-guidance/;* U.S. Equal Emp't Opportunity Comm'n, EEOC–NVTA–2022–2, The Americans with Disabilities Act and the Use of Software, Algorithms, and Artificial Intelligence to Assess Job Applicants and Employees (2022), *https://www.eeoc.gov/laws/guidance/americans-disabilities-act-and-use-software-algorithms-and-artificial-intelligence.*

or consider future rulemaking related to the application of section 504 to disability discrimination that results from the use of algorithms, automated decision-making, and artificial intelligence. Anyone interested in sharing views or comments on these issues should do so by sending the information by letter to the Office for Civil Rights at U.S. Department of Health and Human Services, Office for Civil Rights, Attention: Disability Information, RIN 0945–AA15, Hubert H. Humphrey Building, Room 509F, 200 Independence Avenue SW, Washington, DC 20201 or by email to the Office for Civil Rights at *504@hhs.gov.*

Comment: The Department sought comment on the extent to which, despite indicating that § 84.57 would not apply to academic research alone, the provision would have a chilling effect on academic research. The majority of commenters indicated their belief that, rather than chill academic research, § 84.57 would spur an expansion in research making use of nondiscriminatory alternatives to the QALY and research further developing and refining such alternative measures. In contrast, a commenter expressed concern that prohibiting methods of value assessment that discount the value of life extension on the basis of disability would chill academic research as researchers would be less likely to invest time and resources into generating research findings that cannot inform decision-making.

Response: The Department agrees that the proposed provision may spur an expansion in research making use of nondiscriminatory methods of value assessment and research further developing and refining such alternative measures. While we recognize that researchers may orient their time and resources into generating research findings using nondiscriminatory methods that can inform health care resource allocation and decision-making and away from discriminatory methods that cannot be used for such purposes, we see this as a possible positive feature of this regulatory provision. Given the existence of nondiscriminatory options and the Department's carefully targeted approach to addressing disability discrimination in value assessment, we do not believe this represents a chilling of academic research into value assessment as a whole.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.57 as proposed with no modifications.

Children, Parents, Caregivers, Foster Parents, and Prospective Parents in the Child Welfare System (§ 84.60)

The Department proposed in § 84.60 to address the wide range of discriminatory barriers that individuals with disabilities face when accessing child welfare systems. These included a failure to provide reasonable modifications as required of all recipients in proposed § 84.68(b)(7). It also included the failure to place children in the most integrated setting appropriate to the needs of the child as required by existing § 84.4(b)(2), proposed § 84.68(d), and the specific integration requirements contained in proposed § 84.76. The preamble provided examples of the violation of the most integrated setting requirement in the child welfare setting.

The Department sought comment on additional examples of the application of the most integrated setting requirement to child welfare programs and welcomed comment on any additional points for consideration regarding integration of children with disabilities in child welfare contexts.

Proposed § 84.60(a)(1) prohibited exclusion of qualified individuals with disabilities in the child welfare system.

Proposed § 84.60(a)(2) provided that prohibited actions include discrimination based on speculation, stereotypes, or generalizations about whether parents and others with disabilities listed in the heading of the section can safely care for a child and decisions based on speculation, stereotypes, or generalizations about an individual with a disability.

Proposed § 84.60(b) set forth a non-exhaustive list of additional prohibitions.

The Department requested comment on the list of prohibited activities, especially on whether commenters believe it is complete.

Proposed § 84.60(c) would require recipients to establish referral procedures for individuals who need or are believed to need adapted services or reasonable modifications, and to ensure that tests, assessments, and other evaluation materials, are tailored to assess specific areas of disability-related needs.

The Department sought comment on how agencies would implement these referral procedures, ensure that service providers use the methods described, and prohibit the use of IQ alone as the basis for a parenting evaluation.

The comments and responses regarding § 84.60 are set forth below.

General

Comment: Many commenters enthusiastically supported the revisions to the child welfare section, echoing the Department's explanation in the NPRM that children, parents, caregivers, foster parents, and prospective parents with disabilities encounter a wide range of discriminatory barriers when accessing critical child welfare programs and services. Some commenters submitted stories of discrimination against foster parents and caregivers with disabilities who could provide safe and proper care to a child, such as a prospective adoptive parent being denied solely on the basis of having spinal muscular atrophy, which required the prospective mother to use a wheelchair.

Response: The Department believes the experiences shared with the Department through public comments underscore the importance of eliminating discrimination in child welfare services.

Comment: Several commenters asked the Department to include explicit reference to other child welfare statutes, such as title IV–E of the Social Security Act of 1935 (Pub. L. 96–272, 94 Stat 500), the Family First Prevention Services Act (Pub. L. 115–123, 132 Stat 64), and the Indian Child Welfare Act (Pub. L. 95–608, 92 Stat 3069). Commenters asked that the Department elaborate on how section 504 interacts with the requirements of these laws.

Response: Compliance with section 504 is consistent with the Federal child welfare statutes, but the Department declines to incorporate their requirements by reference because those other laws are beyond the scope of this rulemaking. We note that § 84.3 makes clear that part 84 ''does not invalidate or limit the remedies, rights, and procedures of any other Federal laws, or State or local laws (including State common law) that provide greater or equal protection for the rights of individuals with disabilities, or individuals associated with them.'' We will continue to work with our sister agencies within HHS as questions or comments arise regarding various child welfare statutes and regulations, including section 504, and will provide guidance and technical assistance as appropriate.

Application of This Section

Comment: Several commenters requested that the term ''youth'' or ''young people'' be added wherever child or children is used to avoid unintentionally excluding individuals over the age of 18 who are receiving child welfare services. Commenters

recommended that the word ''youth'' be used to replace the word ''child'' or ''children,'' or that ''child'' be defined as ''an individual under age 18 and young people aged 18 and over who are eligible for child welfare services pursuant to 42 U.S.C.A. 675 (8).''

Response: ''Qualified individual with a disability'' in paragraph (a) includes individuals of all ages eligible for child welfare services, including individuals over the age of 18. The age of eligibility for State child welfare services is determined by State law, and may include youth up to age 21.[57] These individuals are covered under the existing language, and the proposed addition suggested by commenters could potentially create confusion, and could erroneously imply that these individuals were not already covered.

Comment: Several commenters asked that we elaborate on the different legal forms of parentage in the rule's definition of ''parent,'' and referenced different legal structures such as including Voluntary Acknowledgements of Parentage (VAPs), court orders, marital presumptions, being an intended parent to a child born through assisted reproduction, and functional parenthood (such as de facto parentage).

Response: The Department appreciates commenters' feedback and notes that there are varied ways parents receive legal recognition under State law. However, our current definition of ''parents,'' as ''biological or adoptive parents or legal guardians as determined by applicable State law,'' encompasses the different ways individuals may be recognized by State law as parents.

Comment: Many commenters asked that the child welfare section explicitly reference other sections of the rule, such as the requirements for reasonable modifications and effective communication. For example, several commenters asked that the Department specify that parenting classes and their written materials, any forms or assessments parents are required to fill out, and any information provided to parents, must all be accessible to individuals with disabilities.

Response: The Department affirms that subparts A, B, C, §§ 84.51, 84.52, and 84.54 of subpart F, and subparts G, H, and K apply to all child welfare recipients. The child welfare-specific regulatory language in § 84.60 does not narrow or limit recipients' existing and long-standing obligations under section 504 or the ADA. Rather, specific provisions in this section address several aspects of discrimination that are common in child welfare programs and services. Where an individual with a disability faces discrimination not addressed by these specific provisions, then the broader equal access, equal opportunity, reasonable modifications, and non-discrimination provisions of the regulation, along with the accompanying defenses, shall continue to apply.

Comment: Some commenters asked the Department to add discrimination based on substance use disorder to the list of prohibited activities. Commenters cited that parents and prospective parents, foster parents, and other caregivers in recovery from addiction are often discriminated against for using medications for opioid use disorder (MOUD).

Response: The Department recognizes that discrimination against parents and prospective caregivers in recovery from opioid use disorder and in recovery from other substance use disorders (SUD) is widespread.[58] For example, in August 2023 the OCR settled an investigation resolving a complaint against a county-operated child welfare agency that denied an individual the opportunity to apply to be a foster parent because she receives medication for the treatment of substance use disorder and not based on an analysis of her ability to be an effective foster parent, a violation of her rights under section 504. The Department has previously issued guidance related to MOUD and, as noted in the NPRM's preamble, continues to enforce cases of discrimination against individuals prescribed MOUD.[59] With limited exceptions, the ADA and section 504 do not protect individuals engaged in the current illegal use of drugs, including if an entity takes action against them because of that illegal drug use.[60]

Discriminatory Actions Prohibited (§ 84.60(a))

Comment: Several commenters emphasized the importance of avoiding ''speculation, stereotypes, or generalizations'' in assessing whether a parent's disability poses a direct threat to the child. Commenters also asked that direct threat be added to the language of this section.

Response: This section does not use the language ''direct threat,'' because it covers a broader category of decisions where a covered entity may determine that a parent, caregiver, foster parent, or prospective parent, because of a disability, cannot safely care for a child. These decisions may include but are not limited to, whether a parent poses a direct threat to the child. However, the Department emphasizes while child welfare agencies may make determinations to disqualify a parent or child from services on grounds that they may pose a direct threat to others, such determinations are subject to § 84.75. Child welfare agencies and providers are required by law to ensure the safety of children in the child welfare system, and a key priority of child welfare agencies is the wellbeing of children. The determination of whether a caregiver can provide for a child's safety and wellbeing must be based on facts regarding each individual and not based on stereotypes about people with disabilities. In determining whether an individual poses a direct threat, a recipient must make an individualized assessment based on reasonable judgment from current medical knowledge or the best available objective evidence to ascertain the nature, duration, and severity of the risk to the child; the probability that the potential injury to the child will occur; and whether reasonable modifications of policies, practices, or procedures will mitigate the risk. Where a parent with a disability poses a significant risk to the child's health and safety, recipients would be permitted to delay or deny reunification or delay or deny visitation with a parent.

Child Welfare Question 1 Regarding ''Most Integrated Setting''

Comment: The Department sought comment on additional examples of the application of the most integrated setting requirement to child welfare programs and welcomed comment on any additional points for consideration regarding integration of children with disabilities in child welfare contexts. In response, numerous commenters noted that the most integrated setting for children is the family home with in-home supports and services. Commenters noted that child welfare settings exist on a continuum of integration, with the most integrated setting for a child being receiving

[57] 42 U.S.C. 675 (8) (allowing States to extend services to individuals up to age 21).

[58] *See e.g.*, U.S. Dep't of Health & Human Servs., Off. for Civil Rts., HHS Office for Civil Rights Secures Agreement with Commonwealth of Pennsylvania to Advance the Rights of People in Recovery and Involved in Child Welfare Services (Aug. 8, 2023), *https://www.hhs.gov/about/news/2023/08/08/hhs-office-civil-rights-secures-agreement-commonwealth-pennsylvania-advance-rights-people-recovery-involved-child-welfare-services.html.*

[59] U.S. Dep't Health & Human Servs., U.S. Dep't of Justice, Protecting the Rights of Parents and Prospective Parents with Disabilities: Technical Assistance for State and Local Child Welfare Agencies and Courts under Title II of the Americans with Disabilities Act and section 504 of the Rehabilitation Act (2015), *https://www.hhs.gov/sites/default/files/disability.pdf.*

[60] 42 U.S.C. 12210 (ADA); 29 U.S.C. 705(20)(C) (section 504).

services at home with their parents, followed by properly supported kinship placements, then foster care in a family setting, including when appropriate therapeutic foster care. Commenters noted that congregate care is the least integrated setting, yet it is often the default placement for children with disabilities, particularly disabilities related to mental and behavioral health. Many commenters urged that congregate care placements are only nondiscriminatory when the covered entity has made reasonable modifications to services and supports that could enable children to remain together in the family home. Several commenters asked that we include specific language in the regulatory text describing the criteria for congregate care placements.

Many commenters also noted that ensuring families can remain together at home potentially requires the coordination of multiple covered entities and associated services, including long-term services and supports, home modifications and assistive technology, employment supports and services, community-based mental health services and community resources or supports for people with substance use disorders. A commenter asked the Department to emphasize the harms of certain placements, such as out-of-state placements.

Response: While the Department declines to distinguish explicitly between different congregate care settings or list mandatory criteria for congregate care placements, we reiterate that all children with disabilities in foster care are entitled to receive services in the most integrated setting appropriate to their needs,[61] and congregate care is virtually never the most appropriate long-term setting for children.[62] We agree with commenters that the most integrated setting appropriate for children with disabilities is almost always the family home or a family foster care setting.[63] Recipients should consider and facilitate the full range of services and supports a family may be eligible for to keep parents and children together.

Lastly, while this rule's provisions do affirm the child welfare system's requirements when it interacts with people with disabilities under section 504, the Department's position is that children should not be required to enter or remain in the child welfare system solely to receive disability-related services and supports. The Department notes that child welfare services may have limits based on legal requirements in judicial proceedings for child welfare system involvement. In the event that long term supports are needed outside of foster care, the Department encourages transition planning to assist with continuity of supports and services.

[61] *See, e.g., G.K. by Cooper* v. *Sununu,* No. 21–cv–4–PB, 2021 WL 4122517 (D.N.H. Sept. 9, 2021), allowing a class action to proceed on claims filed by or on behalf of children in foster care alleging violations of the ADA and section 504 based on a State's failure to provide alternatives to congregate care for children with disabilities. *Id.* at *10 (''Unless [the State] could prevail on a fundamental-alteration defense, the State must administer its foster care services in a manner that enables plaintiffs to live in . . . integrated settings.'').

[62] *See, e.g.,* U.S. Dep't of Health & Human Servs., Admin. for Child. & Fam., Children's Bureau, Reducing the Use of Congregate Care, *https://www.childwelfare.gov/topics/permanency/reducing-use-congregate-care/* (''Congregate care settings, such as group homes and residential facilities, are not a substitute for family and should only be used on a time-limited basis when youth require services that are unavailable in a less restrictive environment to address psychological or behavioral needs.''); U.S. Dep't of Health & Human Servs., Admin. for Child. & Fam., Children's Bureau, A National Look at the Use of Congregate Care in Child Welfare, (May 13, 2015) *https://www.acf.hhs.gov/sites/default/files/documents/cb/cbcongregatecare_brief.pdf* (''[T]here is consensus across multiple stakeholders that most children and youth, but especially young children, are best served in a family setting. Stays in congregate care should be based on the specialized behavioral and mental health needs or clinical disabilities of children. It should be used only for as long as is needed to stabilize the child or youth so they can return to a family-like setting.'').

[63] *See, e.g.,* Sandra Friedman et al., *Out-of-Home Placement for Children and Adolescents With Disabilities—Addendum: Care Options for Children and Adolescents With Disabilities and Medical Complexity.* 138:6 Pediatrics: Official Journal of the American Academy of Pediatrics (2016), *https://publications.aap.org/pediatrics/article/138/6/e20163216/52567/Out-of-Home-Placement-for-Children-and-Adolescents?autologincheck=redirected* (''Children and adolescents with significant intellectual and developmental disabilities and complex medical problems require safe and comprehensive care to meet their medical and psychosocial needs. Ideally, such children and youth should be cared for by their families in their home environments. When this type of arrangement is not possible, there should be exploration of appropriate, alternative noncongregate community-based settings especially alternative family homes.); Carrie W. Rishel et al., *Preventing the Residential Placement of Young Children: A Multidisciplinary Investigation of Challenges and Opportunities in a Rural State,* 37 W. Va. Univ. Child. & Youth Servs. Rev. 9 (2014), *http://dx.doi.org/10.1016/j.childyouth.2013.11.027*. The United States has taken the position that even children with intensive behavioral needs have better outcomes in family settings. *See* U.S. Dep't of Justice, Investigation of the State of Alaska's Behavioral Health System for Children (Dec. 15, 2022), *https://www.justice.gov/opa/press-release/file/1558151/download* (''With access to timely and appropriate services, even children with intensive behavioral health needs and a history of congregate facility placement are able to return to or remain in family homes where they are more likely to have improved clinical and functional outcomes, better school attendance and performance, and increased behavioral and emotional strengths compared to children receiving care in institutions.'').

Child Welfare Question 2 Regarding Additional Prohibitions

Comment: The Department requested comment on the list of prohibited activities in § 84.60(b), especially on whether commenters believe it is complete. Commenters offered specific examples of denial, termination, or abridgment of specific services, such as family preservation services, that should be prohibited. These are often short-term services designed to help families cope with significant stresses or problems that interfere with their ability to nurture their children. The goal of family preservation services is to maintain children with their families and may be distinct from reunification services. Several commenters asked that mandatory custody relinquishment, a policy in some jurisdictions where parents are required to relinquish custody of their child with disabilities so that the child may receive services, be added to the list of prohibited activities. Several commenters recommended that the language in § 84.60(b) include all child welfare services. Additionally, multiple commenters recommended that paragraph (b)(3) mirror the language of § 84.68(b)(1)(iii) in the general prohibitions against discrimination section.

Response: The Department appreciates commenters' identification of potential prohibited activities. While paragraph (b) lists additional prohibited activities, the list is not intended to be exhaustive. All child welfare recipients must comply with § 84.68, which prohibits discrimination in all of a recipients' programs and activities including aids, benefits, and services provided by the recipient.

In consideration of comments received, we have added ''any and all services provided by a child welfare agency, including but not limited to . . .'' to paragraph (b)(2) to underscore that no service may discriminate on the basis of disability. We have also added ''family preservation services'' to the paragraph, recognizing that these services help families avoid separation through loss of custody or foster care placement.

The Department noted in the NPRM that the practice of requiring parents to relinquish custody of a child with a disability, so that the child may receive disability-related services, is common in some jurisdictions. For example, a child welfare agency may require parents to relinquish custody so that a minor with a mental illness may receive intensive behavioral health supports in a group home, without any showing of abuse or

neglect by the parent required to forfeit parental rights. Requiring a child to be removed from the family home, on the basis of the child's disability, in order to receive services is discrimination under section 504. To clarify the discriminatory nature of this practice, we have added a prohibition against it in paragraph (b)(5).

Parenting Evaluation Procedures (§ 84.60(c))

Comments: Several commenters asked for the elimination of the use of IQ scores in parental skills evaluation on the basis that IQ may also be discriminatory in the context of intellectual disability. Additionally, commenters suggested that the language regarding tests and assessments in paragraph (c) clarify that no test or assessment should be the sole metric by which to evaluate parenting capabilities. Further, commenters urged that we clarify that parental evaluations should center on assessing parenting capabilities rather than solely assessing or diagnosing parental disabilities.

Response: While the Department declines to prohibit the use of IQ testing, we reiterate that parenting evaluations shall not be based solely on a single general intelligence quotient or measure of the person's disability, rather than their parenting ability. Recognizing the critical role of parental evaluation in many child welfare services, we have added language to clarify that evaluations and risk assessments must be tailored to assess parenting capabilities and support needs, rather than solely evaluating a parent's disability. For greater clarity about the application of nondiscrimination requirements to parenting evaluations, we have revised the text of the section as described in the summary of regulatory changes for this section.

Comment: Many commenters urged parental assessments to consider the availability of natural supports, such as friends and family, who can help a parent with child-rearing responsibilities. Many other commenters cited the importance of considering other supports, such as personal assistants, assistive technology, and parent education programs, in assessing parental capabilities.

Response: The Department agrees with commenters that a nondiscriminatory assessment of parenting capabilities may need to consider natural and paid supports as reasonable modifications that may be used in meeting evaluation criteria. For all recipients, the determination of whether parents are ''qualified'' must be consistent with the definition of ''qualified individual with a disability'' in § 84.10 which states that an individual with a disability may meet the essential eligibility requirements for programs or services with or without reasonable modifications.

Comment: Other commenters noted that functional parenting evaluations should be designed with input from parents with disabilities, who are familiar with the supports and adaptations that can help a parent succeed.

Response: The Department supports this suggestion of a potential best practice for child welfare recipients but declines to include it in the regulation in order to give recipients flexibility in how effective functional parenting evaluations are designed. We will consider future guidance on how child welfare recipients can incorporate the input and perspective of individuals with disabilities in their policies and procedures.

Algorithms

Comment: We received many comments about discrimination in algorithms used by child welfare services. Several commenters highlighted that the algorithms have the potential to discriminate on the basis of disability and other protected classes, and that algorithms can be discriminatory on their face or by producing unlawfully biased products or outcomes.

Response: The Department recognizes this rapidly evolving area of concern. As noted earlier above, section 504 prohibits a recipient from discriminating on the basis of disability, and this encompasses discrimination through a recipient's use of algorithms. This protection would also extend to a child welfare agency's use of algorithmic decision-making tools. We continue to collect information and will consider developing additional guidance, consistent with Executive Orders related to algorithms and artificial intelligence.[64] We also requested information from the public on this issue above.

Training

Comment: Several commenters asked that the rule mandate training related to reasonable modifications, effective communications, and/or disability culture for child welfare staff and foster families. Commenters requested training from the Department for child welfare agencies on how to implement policies and practices in compliance with this section.

Response: Due to the administrative challenge of mandating a single set of training requirements for all recipients, and because doing so is beyond the scope of this rulemaking, we decline to impose specific training requirements and instead leave the details of the specific administrative procedures for ensuring recipient staff's compliance with this section to the discretion of the recipient. However, the Department acknowledges that training on compliance with section 504 and best practices to eliminate barriers for disabled parents and children may help agencies comply with the provisions in this final rule. The Department remains committed to providing technical assistance and education and will consider developing additional guidance as needed, in coordination with ACF.

Summary of Regulatory Changes

For the reasons set forth above and considering comments received, we are finalizing § 84.60 with the following changes: First, we are revising paragraph (b)(2) to clarify that all services offered or provided by the child welfare entity are covered. An additional example of ''family preservation'' is added as well as the clarifying phrase, ''any and all services provided by a child welfare agency, including but not limited to. . . .'' The paragraph now reads: ''Deny a qualified parent with a disability an opportunity to participate in or benefit from any and all services provided by a child welfare agency, including but not limited to, family preservation and reunification services equal to that afforded to persons without disabilities.'' Second, we are adding a new paragraph (b)(5) to clarify that recipients may not require, on the basis of a child's disability, custody relinquishment, voluntary placement, or other forfeiture of parental rights in order for the child to receive services. The new paragraph reads: ''Require children, on the basis on the disability, to be placed outside the family home through custody relinquishment, voluntary placement, or other forfeiture of parental rights in order to receive necessary services.''

Third, we are revising paragraph (c) to clarify that evaluations and risk assessments must be tailored to assess parenting capabilities and support needs, rather than the disability itself. The new paragraph provides that a recipient to which the subpart applies shall establish procedures for referring to qualified professionals for evaluation

[64] *See, e.g.,* E.O. 14110, *Safe, Secure, and Trustworthy Development and Use of Artificial Intelligence,* 88 FR 75191 (Nov. 1, 2023).

those individuals, who, because of disability, need or are believed to need adapted services or reasonable modifications. A recipient shall also ensure that tests, assessments, and other evaluation tools and materials used for the purpose of assessing or evaluating parenting ability are based in evidence or research, are conducted by a qualified professional and are tailored to assess actual parenting ability and specific areas of disability-related needs. Parenting evaluations must be fully accessible to people with disabilities and shall not be based on a single general intelligence quotient or measure of the person's disability, rather than their parenting ability. Assessments of parents or children must be individualized and based on the best available objective evidence.

Subpart G—General Requirements

Subpart G contains general prohibitions and eight specific sections on various topics.

General Prohibitions Against Discrimination (§ 84.68)

Proposed § 84.68 retained several of the general prohibitions in the existing rule and added many provisions for consistency with the ADA title II regulations. Comments received on provisions contained in § 84.68 are set forth below.

General Prohibitions (§ 84.68(a))

Comment: Many commenters supported inclusion of this section to ensure that the section 504 regulations will be enforced in a fair and transparent manner. Others asked us to make clear that all of these prohibitions apply to the medical treatment section.

Response: We appreciate commenters' support for this provision. In fact, the general prohibitions in this section apply throughout the rule and we have added a statement to that effect specifically in the medical treatment section.

Meaning of Solely (§ 84.68(a))

In its section 504 NPRM, the Department proposed to add ''solely'' in the language stating section 504's general prohibition against discrimination at § 84.68(a). That word is not included in the parallel provision of the Department's existing section 504 rule at § 84.4(a). The Department noted that this addition was a technical change to make the regulation's language consistent with the general nondiscrimination language of the statute, and that the language does not exclude the forms of discrimination delineated throughout the rule.

Comments: A number of commenters, including disability rights and civil rights legal organizations, a State Attorney General's office, and a member of Congress, expressed concern with the Department's proposed approach. Some asked that, because the word ''solely'' in section 504 has become a battleground in court cases that threaten to limit disability rights protections, HHS should provide additional regulatory language and guidance to reflect case law, statutory purpose, and congressional action, and to clarify that ''solely'' does not limit prohibited conduct to intentional discrimination. Commenters noted that the Department's preamble language is helpful but suggested that the Department should include regulatory text to ensure that its interpretation has the full force and effect of law. Some commenters referenced a brief filed by the United States in the Supreme Court[65] and, using that brief as a template, suggested that the Department should state that ''solely on the basis of disability'' refers to a causal relationship between the discrimination alleged and the disability, and includes discrimination that results from ''benign neglect,'' indifference, and unintentional disparate-impact discrimination.

Response: The Department agrees that the addition of the word ''solely'' in § 84.68(a) should not limit section 504 to intentional discrimination claims, and the Department did not intend to impose such a limitation in the proposed rule. The Department understands commenters' concern that making that change in the manner intended by the Department without including language in the regulatory text itself invites confusion and possible misinterpretation. We want to ensure the addition of the word ''solely'' does not alter the Department's 46-year history of interpretation of the reach of its section 504 rule.

There is considerable support for the view that section 504 is not limited to intentional discrimination. Almost forty years ago, the Supreme Court ''assume[d] without deciding'' that section 504 prohibits both intentional discrimination based on disability, as well as actions that have a discriminatory impact on people with disabilities, notwithstanding a lack of invidious intent.[66] The Court in *Alexander* v. *Choate* looked to the statements by members of Congress at the time of section 504's enactment and the experience of Federal agencies that found that some types of discrimination against people with disabilities, like those resulting from architectural barriers, were ''primarily the result of apathetic attitudes rather than affirmative animus.''[67] The Court noted that ''[i]n addition, much of the conduct that Congress sought to alter in passing the Rehabilitation Act would be difficult if not impossible to reach were the Act construed to proscribe only conduct fueled by a discriminatory intent.''[68] In the years following *Choate,* the Circuits have uniformly agreed that the failure to reasonably accommodate the disability of an otherwise qualified individual is a form of discrimination prohibited by section 504,[69] and a majority of those courts have also applied or expressed support for a disparate impact theory as well.[70]

The Department also finds support for this approach in the recent position of the United States its amicus brief in the Supreme Court in *CVS Pharmacy, Inc.* v. *Doe.*[71] That brief notes that the language in section 504 is written in the passive voice and makes no reference to any specific actor and accordingly no reference to any actor's intent. Thus, the use of ''solely'' ''is most naturally read to focus on the causal link between the

[65] U.S. Dep't of Justice, Brief for the United States as Amicus Curiae, *CVS Pharmacy, Inc.* v. *Doe,* No. 20–1374 (U.S. Oct. 28, 2021).

[66] *Alexander* v. *Choate,* 469 U.S. 287, 295 (1985) (''Discrimination against the handicapped was perceived by Congress to be most often the product, not of invidious animus, but rather of thoughtlessness and indifference—of benign neglect.'').

[67] *Id.* at 296.

[68] *Id.* at 296–97.

[69] *See, e.g., Wynne* v. *Tufts Univ. Sch. of Med.,* 932 F.2d 19, 23–26 (1st Cir. 1991); *Henrietta D.* v. *Bloomberg,* 331 F.3d 261, 276–77 (2d Cir. 2003); *Taylor* v. *Phoenixville Sch. Dist.,* 184 F.3d 296, 306 (3d Cir. 1999); *Basta* v. *Novant Health Incorp.,* 56 F.4th 307, 315 (4th Cir. 2022); *J.W.* v. *Paley,* 81 F.4th 440, 450 (5th Cir. 2023); *Doe* v. *BlueCross BlueShield of Tenn., Inc.,* 926 F.3d 235, 243 (6th Cir. 2019); *Washington* v. *Indiana High Sch. Athletic Ass'n, Inc.,* 181 F.3d 840, 847 (7th Cir. 1999); *Mershon* v. *St. Louis Univ.,* 442 F.3d 1069, 1076–77 (8th Cir. 2006); *A.G.* v. *Paradise Valley Unified Sch. Dist. No. 69,* 815 F.3d 1195, 1204 (9th Cir. 2016); *Cinnamon Hills Youth Crisis Ctr., Inc.* v. *Saint George City,* 685 F.3d 917, 919 (10th Cir. 2012) (Gorsuch, J.)*; L.E. by and through Cavorley* v. *Superintendent of Cobb Cty. Sch. Dist.,* 55 F.4th 1296, 1301 (11th Cir. 2022); *Chenari* v. *George Washington Univ.,* 847 F.3d 740, 746–47 (D.C. Cir. 2017).

[70] *See, e.g., Ruskai* v. *Pistole,* 775 F.3d 61, 78–79 (1st Cir. 2014); *Nathanson* v. *Medical Coll. of Pa.,* 926 F.2d 1368, 1384 (3d Cir. 1991); *Brennan* v. *Stewart,* 834 F.2d 1248, 1261–1262 (5th Cir. 1988); *McWright* v. *Alexander,* 982 F.2d 222, 228–229 (7th Cir. 1992); *Mark H.* v. *Lemahieu,* 513 F.3d 922, 936–937 (9th Cir. 2008); *Robinson* v. *Kansas,* 295 F.3d 1183, 1187 (10th Cir. 2002), *cert. denied,* 539 U.S. 926 (2003); *American Council of the Blind* v. *Paulson,* 525 F.3d 1256, 1268–1269 (D.C. Cir. 2008). *But see Doe* v. *BlueCross BlueShield of Tenn., Inc.,* 926 F.3d 235, 241 (6th Cir. 2019).

[71] U.S. Dep't of Justice, Brief for the United States as Amicus Curiae, *CVS Pharmacy, Inc.* v. *Doe,* No. 20–1374 (U.S. Oct. 28, 2021).

plaintiff's disability and particular undesired effects, rather than on the motives or intent of the defendant.'' [72]

In determining the Department's interpretation of the meaning of ''solely,'' the Department looks to the types of discriminatory practices that have been part of the Department's section 504 regulation since 1977, including intentional discrimination, as well as practices that have discriminatory effects. Thus, the section 504 regulation would cover the denial of health care services to a patient who uses a wheelchair and is unable to reach their doctor's office because it is only accessible by stairs, or a person who is deaf who is unable to communicate his symptoms to emergency room personnel at the county hospital because of the absence of sign language interpreters.

The Department finds compelling the position taken by the United States in its *CVS* amicus brief which focused on the causal link between the plaintiff's disability and nature of the alleged discriminatory practice, ''rather than on the motives or intent of the defendant.'' [73] The United States provided the following explanation in its brief in *CVS Pharmacy, Inc.* v. *Doe:*

> If a pharmacy requires customers to fill out a paper form to obtain in-network prices for a drug, a blind customer who is otherwise eligible for in-network prices but is unable to complete the form is ''being denied the benefit solely by reason of her disability.'' The causal link that the statute requires is a link between the customer's disability and her lack of access to program benefits. That causal connection can exist, and can reliably be established, even if the pharmacy adopted the paper-form requirement for reasons unrelated to its exclusionary effect on blind persons.[74]

The Department shares this view as to the meaning of ''solely'' in the section 504 regulation. In light of this explanation of our interpretation of the word ''solely,'' as discussed in the NPRM, we find it unnecessary to make any changes in the regulatory text.

Specific Prohibitions

Proposed § 84.68(b)(1)(i) through (vii) listed a series of prohibitions that apply to recipients directly or through contractual, licensing, or other arrangements. Discussed below are comments that we received on the provisions in this section.

Contractual Arrangements (§ 84.68(b)(1)(i))

This section states that a recipient, in providing any aid, benefit, or service, may not, directly or through contractual, licensing, or other arrangement, on the basis of disability, deny a qualified individual with a disability the opportunity to participate in or benefit from the aid, benefit, or service.

Comment: Several commenters asked about the applicability of section 504 when a recipient contracts out certain activities to another entity and the activities of that other entity are not in compliance with section 504. Some requested that we make it clear that recipients cannot contract away their obligations when overseeing large programs such as Medicaid. Others asked us to clarify that recipients have affirmative responsibilities to ensure nondiscrimination by agencies with whom they contract.

Response: We proposed in § 84.68(b)(1) to make clear that when a recipient contracts out activities, that recipient remains responsible for ensuring that the entity with whom it contracts complies with section 504. The size of that entity is irrelevant; the requirements are the same. For more information about Federal financial assistance and contracts, please see the discussion of Federal financial assistance in § 84.10, the Definitions section.

Significant Assistance (§ 84.68(b)(1)(v))

We proposed in this section to provide that a recipient may not aid or perpetuate discrimination by providing significant assistance to an entity that discriminates on the basis of disability in providing any aid, benefit, or service to beneficiaries of the recipient's program.

Comment: A commenter noted that many recipients of Federal financial assistance from the Department provide significant financial support to entities that engage in unlawful disability-based discrimination. The commenter requested additional guidance on the recipient's obligations in this instance.

Response: Section 84.68(b)(1)(v) makes clear that recipients retain responsibility for ensuring that entities to which they provide significant assistance comply with section 504.

Methods of Administration (§ 84.68(b)(3))

This section provides that a recipient may not, directly or through contractual or other arrangements, utilize criteria or methods of administration (1) that have the effect of subjecting qualified individuals with disabilities to discrimination on the basis of disability or (2) that have the purpose or effect of defeating or substantially impairing accomplishment of the objectives of the program or activity with respect to individuals with disabilities or (3) that perpetuate the discrimination of another recipient if both recipients are subject to common administrative control or are agencies of the same State.

Comments: Many commenters strongly supported this section. One commenter noted the importance of this prohibition as applied to clinical trial participants who should be provided with continuing care and, where possible, to continued access to study products. That commenter said that methods of allocation of those products and scarce resources should be subject to this provision. Another commenter said that they strongly support § 84.68(b)(3) because it emphasizes the prohibition of discriminatory methods in the allocation of scarce medical resources. An organizational commenter said that this provision, along with the reasonable modifications section in § 84.68(b)(7), represent commendable steps toward safeguarding the rights of individuals in allocating resources. Another commenter mentioned that this regulation should prohibit the provision of separate gowns and visiting procedures for individuals with substance use disorders.

Comment: We appreciate the commenters' support and agree with the importance of applying the prohibition against methods of administration that discriminate in the clinical studies field as well as throughout this rule. With regard to the organizational commenter who suggested that there not be separate gowns and visiting procedures for individuals with substance use disorders, the Department declines to make that change because under certain circumstances, using different gowns or visiting procedures may not constitute discrimination. However, we note that pursuant to § 84.68(b)(7), recipients must make reasonable modifications in policies, practices, or procedures when necessary to avoid discrimination on the basis of disability, unless the recipient can demonstrate that making the modifications would fundamentally alter the nature of the program or activity.

Licensing and Certification (§ 84.68(b)(6))

This section states that a recipient may not administer a licensing or certification program in a manner that subjects qualified individuals with disabilities to discrimination on the basis of disability, nor may a recipient establish requirements for the programs or activities of licensees or certified entities that subject qualified individuals with disabilities to

[72] *Id.* at 6–7.

[73] *Id.*

[74] *Id.* at 14.

discrimination on the basis of disability, although the programs or activities that are licensed or certified by the recipient are not, by themselves, covered by this part.

Comment: A commenter said that many health care licensing entities discriminate against individuals who use prescribed medicines to treat SUD.

Response: Individuals must generally be permitted to take licensing or certification exams if they are qualified as defined in § 84.10. That section defines a qualified individual with a disability as an individual who, with or without reasonable modifications, removal of barriers, or provision of auxiliary aids and services, meets the essential eligibility requirements to take the exam. In the event of noncompliance, individuals can file complaints with the Department if they see discrimination occurring even if they have not personally experienced discrimination. Procedures for filing complaints are set forth in § 84.98.

Reasonable Modifications (§ 84.68(b)(7))

Section 84.68(b)(7) states that recipients must make reasonable modifications in policies, practices, or procedures when such modifications are necessary to avoid discrimination on the basis of disability, unless the recipient can demonstrate that making the modifications would fundamentally alter the nature of the program or activity.

Most of the comments that we received on this section fall into one of two categories: masks and other infection mitigation measures and supported decision-making. We discuss each topic separately.

Masks and Other Infection Mitigation Measures

Comment: We received many comments on this issue. Multiple commenters said that the discontinuation of some measures used to prevent COVID–19 discriminates against those individuals with disabilities who are particularly vulnerable to severe disease. Many commenters only discussed masks and many commenters requested that the Department provide clear guidance as to what is required with regard to masks and other infection mitigation measures. Various commenters described the response received when they asked health care staff to wear masks, including having their requests denied, and being met with shaming. The Department also received a few comments from individuals with hearing impairments who said that the masks discriminated against them because they prevented lip reading.

Multiple commenters argued that the failure to provide mitigation measures constitutes a violation of § 84.56, which prohibits discrimination in medical treatment. Several commenters suggested possible reasonable modifications, including allowing individuals at risk of infection to wait in their cars for appointments, providing separate waiting rooms and separate entrances, scheduling appointments before or after hours or as the first appointment of the day, providing alternate spaces to wait for appointments, and using telehealth where appropriate.

Response: We appreciate the many commenters who shared their experiences. Regarding infection mitigation measures in general, individuals may be able to obtain reasonable modifications to policies, practices, and procedures such as those mentioned above if such modifications are necessary to avoid discrimination on the basis of disability, unless the recipient can demonstrate that the modifications would fundamentally alter the nature of the program or activity.

Supported Decision-making

Comments: The Department received many comments, mostly from disability rights organizations, that were appreciative and supportive of the preamble discussion of the reasonable modification of supported decision-making. Commenters pointed out that individuals with disabilities are routinely subjected to overly restrictive guardianships where someone appointed by a judge makes decisions on behalf of the individual with a disability. Many noted that supported decision-making allows the individual with disabilities to understand, make, and communicate their preferences and choices in consultation with their supporter. Others described supported decision-making as a powerful tool that allows for self-determination. One commenter mentioned that the implementation of supported decision-making processes does not pose an undue obstacle for recipients but, rather, it increases a person's ability to participate through informed choice.

Several commenters asked that supported decision-making be mentioned in the preamble to the medical treatment section and throughout the preamble, particularly as it relates to consent, while others requested that it be included in the text of the regulation.

One organization requested that the Department develop training materials so that supported decision-making is more accessible and affordable for recipients. They suggested that the training materials address privacy issues and the different ways that a recipient can recognize a supported decision-maker as the personal representative or otherwise authorized third party who can directly receive information. They also suggested development of a template for use by recipients.

Response: We appreciate the uniformly positive input that we received on the reasonable modification of supported decision-making. The Department has explained how the concept of supported decision-making may apply to medical treatment in the discussion of medical treatment and in other places as appropriate. The preamble to § 84.56(c), the consent paragraph in the medical treatment section, discusses examples of how supported decision-making applies to medical treatment decisions, noting that it can be crucial in ensuring that individuals with disabilities are giving informed consent. Although we generally agree with the points made by the commenters in support of supported decision-making, we decline to add mention of this reasonable modification in the regulatory text of the consent provision. We note that the reasonable modification provision is in subpart G, General Requirements and, as such, already applies to the consent provision. It would be duplicative to add another reference to the reasonable modification concept in other provisions of the final rule. Accordingly, we are finalizing § 84.68(b)(7) as proposed without modifications.

Summary of Regulatory Changes

For the reasons set forth above and considering comments received, we are finalizing § 84.68 as proposed with no modifications.

Illegal Use of Drugs (§ 84.69)

In § 84.69(a)(1), we proposed to state that except as provided in paragraph (b), this part does not prohibit discrimination based on current illegal use of drugs.

In § 84.69(a)(2), we proposed to prohibit discrimination based on illegal use of drugs against an individual who is not engaging in current illegal use of drugs and who has successfully completed a supervised drug rehabilitation program or has otherwise been rehabilitated successfully; is participating in a supervised rehabilitation program; or is erroneously regarded as engaging in such use.

In § 84.69(b), we proposed to prohibit a recipient from excluding an individual based on illegal use of drugs from the benefit of programs and activities providing health services and services provided under subchapters I, II, and III of the Rehabilitation Act, which includes, among other things, vocational rehabilitation programs. This provision comes directly from the statute, 29 U.S.C. 705(20)(C). This provision differs from a similar provision in the ADA title II statute and regulations, which prohibit denial of health services or services provided in connection with drug rehabilitation, at 42 U.S.C. 12210(C) and 28 CFR 35.131(b).

Proposed § 84.69(c)(1) addressed drug testing. It proposed to make clear that this part does not prohibit a recipient from adopting or administering reasonable policies or procedures including drug testing designed to ensure that an individual who formerly engaged in illegal use of drugs is not now engaging in illegal use of drugs.

In § 84.69(c)(2), we proposed to provide that nothing in this section shall be construed to encourage, prohibit, restrict, or authorize the conduct of testing for the illegal use of drugs.

The comments and our responses regarding § 84.69 are set forth below.

Comment: Many commenters had concerns about this proposed section. As discussed under the definition of ''illegal use of drugs'' in § 84.10, they said that the regulation's definition of ''current'' represents an outdated view of substance use disorder. Similarly, they believe that the definition of a ''supervised drug rehabilitation program'' in § 84.69(a)(2) has changed over the years. They urged that the term be interpreted broadly to include treatment for a substance use disorder received under the supervision of a medical provider or licensed professional. They noted that since the Rehabilitation Act was enacted in 1973, treatment for individuals with SUD has changed radically and no longer comports with how many individuals receive their treatment. Treatment is often provided in primary care, psychology, and other clinical practices as well as, increasingly, online. Some of these are not stand-alone drug rehabilitation programs, and many involve continuation of treatment on an outpatient basis. Commenters asked that we make explicit that the term ''supervised rehabilitation program'' means any setting where SUD treatment is received under the supervision of a medical provider or other licensed professional. Some suggested that the term be defined in the regulation. Others recommended that the preamble make it clear that the term is to be read broadly and inclusively, reflecting modern day SUD treatment.

Response: Congress has not amended 29 U.S.C. 705(20)(C)(ii), on which the current regulatory text is closely modelled. Because the Department remains bound by the current statutory text, we decline to revise the regulatory language. Although the Department agrees that treatment for SUD has evolved since the enactment of the Rehabilitation Act, we agree with commenters that the best reading of the statutory terms ''supervised drug rehabilitation program'' and ''supervised rehabilitation program'' generally encompass these modern day treatments of substance use disorders.

Comment: Many commenters expressed concerns about § 84.69(b)(2). That section states that a drug rehabilitation program may deny participation to individuals who engage in current illegal use of drugs while they are in the program. As with the meaning of ''supervised rehabilitation program'' and ''current'' illegal use of drugs, they believe this section is similarly outdated and does not comport with modern understanding of drug treatment and recovery. Several commenters noted the irony that the provision allows health care providers to deny treatment to an individual because they are experiencing symptoms of the very disease for which they are seeking help. Some commenters suggested that before denying entrance to a program, recipients should be required to make an individualized determination about whether participation in the program is warranted.

Response: Section 504 provides that the term ''individual with a disability'' ''does not include an individual who is currently engaging in illegal use of drugs, when a covered entity acts on the basis of such use.'' [75] We have retained this language, consistent with the statutory language.

Comment: Several commenters expressed concerns about discriminatory treatment of individuals with SUD, whether the substances are legal or illegal, who are being denied myriad health services. Many provided examples of individuals who were excluded from, for example, nursing homes and emergency rooms at hospitals because of SUD as well as denials of life-saving surgery and organ transplantation. Others said that mental health centers sometimes have blanket policies of denying treatment to all individuals with SUD.

[75] 29 U.S.C. 705(20)(C).

Response: A denial of treatment to individuals with SUD would violate the medical treatment requirement, § 84.56(b)(1), if it is based on biases or stereotypes or any of the other prohibited bases listed in that paragraph. It would also violate § 84.56(b)(2), denial of treatment for a symptom or condition separate from an underlying disability, if a recipient is refusing to provide admission or treatment because of the underlying disability as an individual with SUD. If the denial of treatment was based on or motivated by the fact that the individual is currently engaged in illegal use of drugs, it would violate § 84.69(b), which provides that an individual currently engaged in illegal use of drugs shall not be excluded from the benefits of health services on the basis of their illegal use of drugs if he or she is otherwise entitled to such services.

However, that section must be read in conjunction with § 84.53 which provides in this final rule that recipients who operate any type of health care facility may not discriminate in admission or treatment against an individual with a substance or alcohol use disorder. This prohibition applies to all individuals with SUD, whether engaged in illegal use of drugs or not. See § 84.69(b), prohibiting the denial of health services and services provided under the Rehabilitation Act and discussion of § 84.53 for more information about that section.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.69 as proposed with no modifications.

Maintenance of Accessible Features (§ 84.70)

This proposed section tracks the ADA title II and title III regulations on maintenance of accessible features.

Proposed § 84.70(a) required that recipients maintain in operable working condition those features of facilities and equipment that are required to be readily accessible to and usable by persons with disabilities by section 504 or this part.

Proposed § 84.70(b) stated that the section does not prohibit isolated or temporary interruptions in service or access due to maintenance or repairs.

Proposed § 84.70(c) stated that if the 2010 Standards reduce the technical requirements or the number of required accessible elements below the number required by UFAS, the technical requirements or the number of accessible elements in a facility subject to this part may be reduced in

accordance with the requirements of the 2010 Standards.

The comments and our responses regarding § 84.70 are set forth below.

Comment: We received many comments, including from several organizations representing individuals with disabilities, requesting that this section be revised to encompass all accessibility features and disability modifications, including auxiliary aids and services. Commenters also requested a statement in the regulation that repeated mechanical failures for any reason constitutes a violation of section 504.

One commenter expressed concerns that the rule appears to focus only on mechanical failures. The commenter urged us to emphasize that the maintenance requirement applies not only to mechanical failures but also to interruptions in service or access caused by weather events such as fires, floods, and excessive heat.

Still another commenter said that the regulation should address recipients' responsibilities to continue to provide access to services while interruptions persist. The commenter suggested that language be added to the text of the regulation to clarify that whenever a temporary interruption might deny individuals with disabilities' access to programs and activities, the recipient must provide advance notice of the temporary interruption and must also provide reasonable modifications to individuals with disabilities until the maintenance or repairs are resolved.

Response: The Department appreciates all the commenters' feedback. However, we respectfully disagree with the commenters who suggested that the maintenance requirement be extended to include auxiliary aids and services. Requirements concerning auxiliary aids are contained in § 84.77(b) of the communications subpart. That section requires that recipients provide auxiliary aids and services where necessary to afford an equal opportunity to participate in a program or activity. A recipient would likely be in violation of that section if it were to fail to provide an appropriate auxiliary aid or service or if it were to provide one that was not in working order. Accordingly, it is not necessary to add a reference to auxiliary aids and services in § 84.70.

Comment: Some commenters requested a statement in the rule that repeated mechanical failures for any reason violate section 504.

Response: Section 84.70(b) states that isolated or temporary interruptions in access or service would not be considered violations of this part. Implicit in that statement is that repeated interruptions could still violate the requirements of this part. Allowing obstructions or ''out of service'' equipment to persist beyond a reasonable period of time would violate this part, as would repeated mechanical failures due to improper or inadequate maintenance.

In response to the concern that the regulation is focused on mechanical failures and does not recognize other causes for temporary interruptions such as those that are weather-related, we note that the preamble to the proposed rule makes clear that the requirement goes beyond mechanical failures. The preamble gives the following examples of situations that would violate the rule and that do not involve mechanical failures: storing excess furniture or supplies in the larger, accessible toilet stall; putting potted plants in front of elevator buttons; and placing ploughed snow in an accessible parking spot.

With regard to the commenter who asked that the rule require advance notice of temporary interruptions and provision of reasonable modifications in such instances, we agree that reasonable modifications can be requested in the event of temporary interruptions. Section 84.68(b)(7) requires that recipients provide reasonable modifications whenever necessary to provide an equal opportunity to benefit from its programs or activities unless the recipient can demonstrate that making the modifications would result in a fundamental alteration of the program or activity. For example, an individual with a mobility disability arrives at a building for a meeting with someone whose office is on the fifth floor and discovers that the one accessible elevator is out of service. A reasonable modification might be for the person on the fifth floor to come downstairs and meet the individual somewhere on the ground floor or in a nearby building. Providing notice of a temporary interruption whenever possible is a best practice, but not a requirement of section 504. For example, if a recipient knows that an elevator will not be working during a certain time in the future, it would be a good practice to put up a sign to that effect. However, there may be times when advance notice is not possible such as when an individual with a disability attempts to use a wheelchair lift and a mechanical problem is discovered. In the event the recipient knows in advance that there will be a temporary interruption in service, is aware that an individual with a disability is scheduled to come to the building, and has that person's contact information, it would be helpful for the recipient to notify that individual in advance. However, we decline to revise the rule to require such notice since it is not always possible to do.

Summary of Regulatory Changes

For the reasons set forth above we are finalizing § 84.70 as proposed with no modifications.

Retaliation or Coercion (§ 84.71)

This section is identical to the retaliation provision in the ADA title II regulations. Section 84.71(a) proposed to prohibit a recipient from discriminating against any individual because that individual has opposed any act or practice made unlawful by this part, or because that individual made a charge, testified, assisted, or participated in any manner in an investigation, proceeding, or hearing under section 504 or this part.

Section 84.71(b) proposed to prohibit a recipient from coercing, intimidating, threatening, or interfering with any individual in the exercise or enjoyment of, or on account of their having exercised or enjoyed, or on account of their having aided or encouraged any other individual in the exercise or enjoyment of any right granted or protected by section 504.

This provision protects not only individuals who allege a violation of section 504 or this part, but also any individuals who support or assist them. This section applies to all investigations or proceedings initiated under section 504 or this part without regard to the ultimate resolution of the underlying allegations. The proposed regulation had another prohibition against intimidatory or retaliatory acts. Section 84.98 adopts the procedures of title VI of the Civil Rights Act of 1964. Section 80.7 of the title VI regulations (45 CFR 80.7) contains a provision that is similar to § 84.71(a) but includes a mandate that the identity of complaints be kept confidential except to the extent necessary to carry out the purposes of this part.

The comments and our responses to them regarding § 84.71 are set forth below.

Comment: We received supportive comments on this section. One disability rights organization said that retaliation should be prohibited in the strongest terms possible because it is very common and very difficult to prove. Several individuals described their experiences with retaliation when their complaints about alleged discrimination were ignored.

Response: We appreciate the commenters' support of the section and

agree that protection against retaliation is crucial. We note that the final rule retains in subpart K the adoption of title VI procedures. As noted above, those procedures include another prohibition against retaliation.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.71 as proposed without modification.

Personal Services and Devices (§ 84.72)

Proposed § 84.72 was identical to the provision in the ADA title II regulations, 28 CFR 35.135. It stated that this rule does not require recipients to provide individuals with disabilities with personal devices, such as wheelchairs; individually prescribed devices such as prescription eyeglasses or hearing aids; readers for personal use of study; or services of a personal nature, including assistance in eating, toileting, or dressing. The NPRM also noted that where personal services are customarily provided as part of a recipient's programs or activities, then these personal services should also be provided to persons with disabilities.[76]

The comments and our responses to them regarding § 84.72 are set forth below.

Comment: Several commenters expressed concern that this provision was written so broadly that it would interfere with the requirements in other parts of the proposed rule, including the requirement to provide reasonable assistance to persons using accessible medical equipment, for example, including helping a person who uses a wheelchair to transfer from their wheelchair to the exam table or diagnostic chair, as well as the variety of obligations to provide auxiliary aids. An organization representing persons who need communication tools and supports noted that devices used for communication are often not treated as covered auxiliary aids or services but as personal devices and, as a result, are not provided to persons with communication needs who require them to receive, for example, health care not as effective as that provided to others. This comment suggested adding regulatory text that, where personal devices and services are customarily provided as part of a recipient's program or activities, then these personal devices and services should also be provided to persons with disabilities.

Response: The Department is aware that many programs funded by the Department include, as a regular feature of the program, the provision of personal care services. Hospitals, nursing homes, child welfare services, and home and community-based services (HCBS), by their very nature, routinely provide assistance in eating, dressing, and toileting, the type of personal care services specifically not required by this provision. The Department reiterates its statement from the NPRM that where personal devices and services are customarily provided as part of a recipient's program or activities, then these personal devices and services should also be provided to persons with disabilities. However, it is important to preserve parity with the ADA regulations given Congress's intent that the ADA and section 504 be interpreted consistently and to reduce confusion for both recipients and individuals with disabilities. Therefore, the Department declines to add this statement to the regulatory text but emphasizes that this provision should not be interpreted as a blanket allowance for recipients to deny personal devices and services to individuals with disabilities that the recipient would customarily provide to individuals without disabilities as part of its programs and activities. The supplementary information accompanying DOJ's title III ADA regulation includes this interpretation as well.[77]

Comment: Another commenter on § 84.72 noted that the rule should be changed to make clear that recipients cannot require persons with disabilities to be separated from their own personal devices and to then function without their devices, for example, prohibiting persons who use wheelchairs from being told that they cannot take their own wheelchairs with them when being transported to the hospital.

Response: The Department does not believe it is necessary to add regulatory text to address this situation, but notes that there are circumstances in which recipients are prohibited from separating persons with disabilities from their personal devices that they need to function. For example, an ambulance company that receives Federal funds from HHS is called to the scene of an automobile accident and is going to take a person with a disability who uses a wheelchair to the emergency room of a hospital. The ambulance service, a recipient subject to the general prohibitions against excluding individuals with disabilities in § 84.68, generally cannot pick up the person and leave the wheelchair, an expensive piece of accessible personal equipment, behind at the scene of the accident and expect the person with the disability to recover their wheelchair. The Department recognizes that there may be room or other limitations in the ambulance itself, but that does not relieve the ambulance service of any responsibility to assist in returning the wheelchair to the person with a disability, which may be needed at the site where the person with the disability is being transported. As a recipient, the ambulance service is subject to all of the general prohibitions in § 84.68 which states that individuals with disabilities may not be excluded from participation in or be denied the benefits of their programs or activities. In situations like this, the ambulance company can have a policy or agreement in place to deal with the transport of a wheelchair that might not fit into the ambulance itself.

Similarly, in situations where a person with a speech disability enters a hospital or a nursing home with their personal communication device that they use because they cannot rely on speech alone to be heard and understood by others, the recipient hospital or nursing home must not separate the person from their device, which would deprive the person with a disability of the ability to communicate with others. The Department notes that DOJ has followed a similar policy in addressing concerns where, for example, police may make an arrest of a wheelchair user and must transport both the person and their accessibility equipment to the police station.

Summary of Regulatory Changes

For the reasons set forth above and considering comments received, we are finalizing § 84.72 as proposed with no modifications.

Service Animals (§ 84.73)

Proposed § 84.73 addressed service animals and tracks the ADA title II regulations.[78] Proposed § 84.73(a) stated that generally recipients shall modify its policies, practices, or procedures to permit the use of a service animal by an individual with a disability. The rule, in proposed § 84.10, defined a service animal as any dog that is individually trained to do work or perform tasks for the benefits of an individual with a disability.

Proposed § 84.73(b) contained detailed requirements for recipients and

[76] 88 FR 63478.

[77] 28 CFR part 36, appendix C (1991) (addressing § 36.306) (''Of course, if personal services are customarily provided to the customers or clients of a public accommodation, *e.g.,* in a hospital or senior citizen center, then these personal services should also be provided to persons with disabilities . . .'').

[78] 28 CFR 35.136.

handlers of service animals, including when a recipient may ask an individual with a disability to remove the service animal from the premises (§ 84.73(b)), that the service animal shall be under the control of its handler (§ 84.73(d)), that the recipient is not responsible for the care and supervision of a service animal (§ 84.73(e)), that the recipient shall not ask about the nature or extent of a person's disability, but may ask if the animal is required because of a disability and what work or task the animal has been trained to perform (§ 84.73(f)), that individuals with disabilities shall be permitted to be accompanied by their service animals in all areas of the recipient's facilities where members of the public go (§ 84.73(g)), and that recipients are not allowed to require an individual with a disability to pay a surcharge (§ 84.73(h)). Proposed § 84.73(i) stated that a recipient shall make reasonable modifications in policies, practices, or procedures to permit the use of a miniature horse by an individual with a disability and it provided assessment factors to determine whether reasonable modifications can be made to allow a miniature horse into a specific facility.

The comments and our responses regarding § 84.73 are set forth below.

General comment: The comments that the Department received on § 84.73 were uniformly supportive. Commenters noted that DOJ's ADA regulations were crafted through years of experience and a duly compassionate outlook and that having the same service animal regulation for section 504 as for title II of the ADA will provide necessary clarity for persons who work with service animals and health care and social service providers that receive Federal funding.

Comment: Some commenters recommended adding the example of ''carrying an individual's speech-generating device'' as an example of the type of work or service that a service animal could be trained to do.

Response: The Department agrees that service animals may be used to assist persons with communication disabilities and that recipients should be made aware of this possibility so that they do not unnecessarily inquire of persons with communication disabilities about the nature of the work that the service animal performs for the person. However, the Department is not adding language to the regulatory text, because adding phrases here that are not found in DOJ's ADA regulations on service animals may cause confusion.

Comment: The Department received several comments on the use of service animals in health care settings. An entity that operates a hotline providing guidance to service animal handlers and to recipients noted that over 70% of their callers addressed access challenges in health care facilities due to the presence of service dogs.

Response: The Centers for Disease Control and Prevention (CDC) notes there is no evidence that suggests that animals pose a more significant risk of transmitting infection than people; therefore, service animals should not be excluded from such areas unless a patient's situation or a particular animal poses risk that cannot be mitigated through reasonable measures.[79] Thus, the Department notes that under the final rule, a health care facility generally must permit a person with a disability to be accompanied by a service animal in all areas of the facility in which that person would otherwise be allowed. There are some exceptions, however. Consistent with case law and CDC guidance, it is generally appropriate to exclude a service animal from limited-access areas that employ general infection-control measures, such as operating rooms and burn units. Usually, a service animal may accompany its handler to such areas as admissions and discharge offices, the emergency room, inpatient and outpatient rooms, examining and diagnostic rooms, clinics, rehabilitation therapy areas, the cafeteria and vending areas, the pharmacy, restrooms, and all other areas of the facility where health care personnel, patients, and visitors are permitted without added precaution.

Comment: Several commenters asked for clarification on issues related to the phrase ''under the control of its handler.'' Commenters stated that this clarification should help prevent discrimination against minors and persons with severe disabilities who are sometimes viewed as incapable of acting as the handler of their own service dog due to age or false assumptions and stereotypes about their disability. Other commenters expressed concern about handlers who are not able to physically control their service dog. Commenters noted that people with mental and communication disabilities are increasingly using service dogs and their handlers may not be able to issue verbal commands but can control their service dog through gestures and nonverbal means.

Response: The Department agrees that the handler of a service animal is most often an individual with a disability. The Department's rule at § 84.73(d) notes that one way for an individual with a disability to exercise control over their service animal is by ''voice control, signals, or other effective means.'' This language encompasses gestures and nonverbal means of controlling a service dog.

Comment: Some commenters noted that some court decisions have applied the concept of reasonable modification to § 84.73(e), which states that the recipient is not responsible for the care and supervision of a service animal. The comments seek clarification that providing some assistance to a person with a disability while they handle or care for their service dog may be required as a reasonable modification as long as it does not rise to the level of a fundamental alteration and is consistent with the type of assistance provided to other people with or without disabilities.

Response: The Department notes that DOJ in its ''Frequently Asked Questions about Service Animals and the ADA,'' states that the handler is responsible for caring for and supervising the service animal, which includes toileting, feeding, and grooming.[80] However, a school or similar entity operating in the K–12 context may be required to provide some assistance, which is short of care or supervision, to enable an individual with a disability to handle their service animal.[81]

Recipients are not obligated to supervise or otherwise care for a service animal. This guidance specifically addresses patients in hospital care who have service animals with them in their hospital room. It states that, if the patient is not able to care for the service animal, the patient can make arrangements for a family member or friend to come to the hospital to provide these services, as it is always preferable that the service animal and its handler not be separated.[82] In addition, the CDC has stated that care of the service animal remains the obligation of the person with the disability, not the health care staff.[83]

[79] Ctrs. for Disease Control & Prevention, Environmental Infection Control Guidelines, Animals in Health-Care Facilities (Nov. 5, 2015). *https://www.cdc.gov/infectioncontrol/guidelines/environmental/background/animals.html.*

[80] U.S. Dep't of Justice, *Frequently Asked Questions about Service Animals and the ADA* (2020), Question 9, *https://www.ada.gov/resources/service-animals-faqs/.*

[81] U.S. Dep't of Justice, *Frequently Asked Questions about Service Animals and the ADA* (2020), Question 27, *https://www.ada.gov/resources/service-animals-faqs/.*

[82] U.S. Dep't of Justice, *Frequently Asked Questions about Service Animals and the ADA* (2020), Question 15, *https://www.ada.gov/resources/service-animals-faqs/.*

[83] *See* Ctrs. for Disease Control & Prevention, *Environmental Infection Control Guidelines, Animals in Health-Care Facilities* (Nov.5, 2015) *https://www.cdc.gov/infectioncontrol/guidelines/environmental/background/animals.html.*

Comment: Several commenters noted that the use of miniature horses as a form of reasonable modification of policy has worked well with ADA title II rules and should be added to the Department's section 504 rule. A trade organization noted that, while miniature horses can serve persons with disabilities, they are legally recognized as livestock and should be included as a separate entity from service animals. A legal rights advocacy organization stated that miniature horses may work best for higher weight or tall individuals, and stated the importance of including obesity as covered by section 504, as that would help ensure that higher weight individuals will be determined to be persons with disabilities and entitled to reasonable modification.

Response: The Department agrees that miniature horses, under § 84.73(i), are not included in the definition of service animal, which is limited to dogs, and that they are legally recognized as livestock. However, the regulatory text makes it clear that a recipient must make reasonable modifications in policies, practices, or procedures to permit use of a miniature horse by an individual with a disability if the animal has been individually trained to do work or perform tasks for the benefit of the individual with a disability. In the discussion of the definition of disability above at § 84.4, the Department noted that obesity could be considered a physical or mental impairment and that, if it substantially limited one or more of a person's major life activities, would qualify as a disability. In this case, a qualifying higher weight individual may be able to avail themselves of the use of miniature horses as a form of reasonable modification of polices, practices, or procedures.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.73 as proposed with no modifications.

Mobility Devices (§ 84.74)

This section in the section 504 NPRM was identical to the ADA title II regulation.[84] Proposed § 84.74(a) provided that recipients shall permit individuals with mobility disabilities to use wheelchairs and manually-powered mobility aids, such as walkers, crutches, canes, braces, or other similar devices designed for use by individuals with mobility disabilities in any areas open to pedestrian use.

Section 84.74(b) proposed to require a recipient to make reasonable modifications in its policies, practices, or procedures to permit the use of other power-driven mobility devices by individuals with mobility disabilities, unless a recipient can demonstrate that the class of other power-driven mobility devices cannot be operated in accordance with legitimate safety requirements. The rule, in proposed § 84.10, defined other power-driven mobility device to mean any mobility device powered by batteries, fuel, or other engines—whether or not designed primarily for use by individuals with mobilities disabilities—that is used by individuals with mobility disabilities for the purpose of locomotion.

Proposed § 84.74(b)(2) listed the factors that recipients would be required to consider in determining whether to permit other power-driven mobility devices on their premises, including the type, size, weight, dimensions, and speed of the device; the volume of pedestrian traffic; the facility's design; whether the facility is indoors or outdoors; the availability of storage space if requested; and whether the use of the device creates a substantial risk of serious harm to the environment or natural and cultural resources.

Proposed § 84.74(c)(1) would prohibit a recipient from asking an individual using a wheelchair or other power-driven mobility device questions about the nature and extent of the individual's disability. Proposed § 84.74(c)(2) would permit a recipient to ask a person using an other power-driven mobility device to provide a credible assurance that the mobility device is required because of the person's disability, including a valid, State-issued parking placard or other State-issued proof of disability, or in lieu of such documents, a verbal representation, not contradicted by observable fact, that the other power-driven mobility device is being used for a mobility disability.

The comments and our responses to them regarding § 84.74 and related terms are set forth below.

Comment: Commenters were generally appreciative of the Department's decision to adopt the approach taken by DOJ on mobility devices in § 84.74. Some commenters expressed concern that the phrase ''other power-driven mobility devices'' in § 84.74(b) could be interpreted to include scooters and power chairs commonly used by persons with disabilities, so they recommended that the Department clarify that higher capacity wheelchairs and scooters are covered in § 84.74(a), and not in § 84.74(b). A commenter providing health care made the case that the Department should exempt health care facilities from having to admit devices like Segways®, golf carts, and other motorized devices because allowing them into the facility will put patients in harm's way. One commenter noted that some recipients, including nursing homes, use blanket bans of power wheelchairs to exclude individuals with disabilities from programs and services.

Response: The Department notes that proposed § 84.74(a) specifically concerns ''wheelchairs'' and that the definition of ''wheelchair'' in § 84.10 includes a ''power-driven device designed primarily for use by an individual with a mobility disability for the main purpose of indoor, or of both indoor and outdoor locomotion.'' This definition includes scooters and power wheelchairs that are specifically designed for the use of persons with mobility disabilities. It contrasts with the definition of other power-driven mobility devices, which are not necessarily designed primarily for the use of persons with mobility disabilities. This definition of other power-driven mobility devices encompasses golf carts and electronic personal assistance mobility devices such as the Segway®. Thus, § 84.74(a) includes scooter and power wheelchairs designed for the use of persons with mobility disabilities, and § 84.74(b) includes golf carts, Segways®, and other similar motorized devices that have not been primarily designed for persons with mobility disabilities.

The Department believes that the processes established by § 84.74 will allow hospitals and other recipients to make reasonable and reasoned decisions about whether and how to allow other power-driven mobility devices into their facilities. Section 84.74(b)(1) provides that recipients shall make reasonable modifications in its policies, practices, or procedures to permit the use of other power-driven mobility devices by individuals with mobility disabilities, unless the recipient can demonstrate that the class of such devices cannot be operated in accordance with legitimate safety requirements. Section 84.74(b)(2) provides a list of assessment factors that recipients can use to consider in making determinations concerning whether and how the recipient will allow different types or classes of other power-driven mobility devices into its facilities. The Department believes that this process will allow hospitals and others to develop and issue policies that balance the need for patient safety with the needs of persons with disabilities who

[84] 28 CFR 35.137.

use other power-driven mobility devices in their facilities.

For example, using these assessment factors, a county hospital may decide that it can allow electronic personal assistance mobility devices (EPAMDs), which are other power-driven mobility devices under proposed § 84.10 in any areas open to pedestrian use, including the cafeteria and general patient rooms, but not in other specified areas of the hospital (*e.g.,* the emergency room or other areas with high traffic and cramped quarters), as long as operators do not operate the device faster than pedestrians are walking. A recipient might also decide, using the assessment factors, that due to air quality concerns, for example, gas-powered devices would not be allowed in the hospital's indoor facilities; or that certain classes of devices, such as golf carts, could not be allowed for safety reasons, because the facility's corridors or aisles are not wide enough to accommodate those vehicles and are heavily trafficked. Because § 84.74 establishes a procedure and sets forth appropriate assessment standards for recipients, the Department does not view it as necessary to exempt health care facilities from the requirements of this section in its final rule. In addition, the Department notes that health care facilities, both public and private, have already been subject to this same provision since 2010 under DOJ's ADA regulations for titles II and III.

As to the comment on blanket bans on the use of motorized wheelchairs in nursing homes, the Department notes that such bans may violate section 504. The Department's final rule requires recipients to allow the use of wheelchairs, including power-driven ones, and contains several disability-related provisions that require a recipient to tailor its approach based on the specific circumstances rather than apply blanket bans. For example, recipients need not allow an individual to participate in or benefit from the programs or activities of that recipient if it concludes, after an individualized assessment, that the individual poses a ''direct threat'' as set forth in § 84.75. Similarly, ''a recipient may impose legitimate safety requirements necessary for the safe operation of its programs or activities'' in § 84.68(h). However, the recipient must ensure that ''its safety requirements are based on actual risks, not on mere speculation, stereotypes, or generalizations about individuals with disabilities.'' In addition, § 84.68(b)(8) provides that a ''recipient shall not impose or apply eligibility criteria that screen out or tend to screen out an individual with a disability or any class of individuals with disabilities from fully and equally enjoying any program or activity, unless such criteria can be shown to be necessary for the provision of the program or activity being offered.''

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.74 as proposed with no modifications.

Direct Threat (§ 84.75)

Proposed § 84.75(a) stated that nothing in this part requires a recipient to permit an individual to participate in or benefit from programs or activities when that individual poses a direct threat.

Proposed § 84.75(b) stated that except as provided in paragraph (c), in determining whether an individual poses a direct threat, a recipient must make an individualized assessment, based on reasonable judgment that relies on current medical knowledge or on the best available objective evidence, to ascertain: the nature, duration, and severity of the risk; the probability that the potential injury will actually occur; and whether reasonable modifications of policies, practices, or procedures or the provision of auxiliary aids or services will mitigate the risk.

Proposed § 84.75(c) provided that in the area of employment, the individualized assessment must be made according to the ADA title I regulations of the Equal Employment Opportunity Commission.

The comments and our responses regarding § 84.75 are set forth below.

Comments: The Department received many comments, including from multiple organizations representing individuals with disabilities, stating that the direct threat defense has been misunderstood, overused, and misconstrued and has been used to justify blanket bans on wheelchairs, power wheelchairs, and other mobility assistive devices based on generalizations and stereotypes. The commenters asked that we clarify that the direct threat analysis should be focused on the individual and requires a fact-specific, individualized assessment.

Response: As set forth in the definition of direct threat in § 84.10, the standard to apply when determining whether a situation poses a direct threat is whether it is a significant risk to the health and safety of others that cannot be eliminated by a modification of policies, practices, and procedures, or by the provision of auxiliary aids and services. In determining whether that standard has been met, the Department affirms the notion that the determination is a factual one that requires an individualized assessment and that it cannot be used to impose blanket bans on, for example, mobility devices without consideration of the appropriate factors.

Comment: An organization representing an association of State government agencies highlighted the potential unintended consequences of the direct threat text. They focused on a subgroup of individuals with disabilities who have impulsive and explosive behaviors that can sometimes result in injury to themselves or others. The commenter noted that in these types of situations, many States have developed small community service settings for those individuals rather than providing services in more restrictive settings such as State institutions. The commenters were afraid that if the Department were to keep the direct threat language as in the proposed rule, individuals who need extraordinary measures will be permanently assigned to institutional care. They suggested the addition of a paragraph in the text indicating that if all reasonable modifications have been made to mitigate the risk and the probability of potential injury still exists, the recipient must structure the program with sufficient staff well trained to disarm and defend against the threatening behavior.

Response: The Department thanks the commenters for their thoughtful suggestions for additions to the direct threat text. Section 84.68(b)(7) contains the Department's reasonable modifications requirement. That section requires recipients to provide reasonable modifications to policies, practices, and procedures when such modifications are necessary to avoid discrimination on the basis of disability, unless the recipient can demonstrate that making the modifications would fundamentally alter the nature of the program or activity. And § 84.76 contains the Department's integration requirement. These regulations require ''reasonable'' modifications but commenters want the mandate to include ''extraordinary'' modifications. The Department is unable to change the direct threat text to require more of recipients than is required by the reasonable modifications and integration provisions. Recipients can certainly decide to provide more than is required by section 504 to serve particular individuals but we cannot mandate that they do so. Accordingly, we decline to change the regulatory text.

Summary of Regulatory Changes

For the reasons set forth above and considering comments received, we are retaining § 84.75 as proposed with no modifications.

Integration (§ 84.76)

Proposed § 84.76 expanded upon the integration mandate in the existing section 504 regulations at § 84.4(b)(2) and the integration requirement in proposed § 84.68(d).

Proposed § 84.76(a) addressed the application of the section.

Proposed § 84.76(b) prohibited administering a program or activity in a manner that results in unnecessary segregation of individuals with disabilities.

Proposed § 84.76(c) defined a segregated setting as one where individuals with disabilities are unnecessarily separated from people without disabilities. Such settings are populated exclusively or primarily with individuals with disabilities, and may be characterized by regimentation in daily activities; lack of privacy or autonomy; or policies limiting visitors or limiting individuals' ability to engage freely in community activities and to manage their own activities of daily living.

The Department invited comment on whether the definition of ''segregated setting'' should be expanded.

Proposed § 84.76(d) provided a non-exhaustive list of specific prohibitions.

Proposed § 84.76(e) stated that a recipient may establish a defense to the application of this section if it can demonstrate that a requested modification would fundamentally alter the nature of its program or activity.

The Department invited comment on what may constitute a fundamental alteration for recipients who are not public entities, for example, an individual skilled nursing facility responsible for identifying and preparing individuals who can and want to be discharged to available community-based services.

The comments and our responses regarding § 84.76 are set forth below.

General

Comments: Most commenters enthusiastically supported the clarification of integration requirements in this section. We received supportive comments from individuals, advocacy organizations, State government and provider associations, and managed care plans, among others. Commenters emphasized the importance of integrated services to ensure individuals with disabilities can live, work, and engage in the community like people without disabilities.

Response: The Department appreciates support for this section and intends for the new provisions to clarify the existing requirements of covered entities.

Comments: Several commenters, including parents of adult children with disabilities and parent advocacy organizations, expressed concerns related to the legitimacy of the integration provision and shared the opinion that institutional settings are the only appropriate option for some individuals with disabilities. Further, these commenters alleged that failure to ensure the availability of institutional placements is discrimination against individuals with disabilities.

Response: While this section elaborates on the prior rule's language requiring programs and services to be administered in the most integrated setting, the additions are intended to codify longstanding case law and Federal guidance with respect to the obligations of covered entities to serve individuals with disabilities in the most integrated setting appropriate to their needs.[85] The Department recognizes several commenters' opposition to the integration mandate. We note that contrary to some parent advocacy groups' position, the integration mandate in section 504 or title II does not require recipients or public entities to offer services, programs, or activities in institutional settings.[86] We reiterate this section clarifies existing obligations under Federal law to help recipients deliver services in the most integrated setting appropriate to a person's needs.

Comment: A commenter suggested that the Department's integration mandate discriminates against those persons with severe or multiple disabilities who may need the services of institutional settings. Another commenter representing State government stated that the proposed rule violates the constitutional principle of separation of powers.

Response: The Department does not agree that its integration requirement in § 84.76(b) discriminates against persons with severe disabilities. That section requires providing a person with a disability with the most integrated setting ''appropriate to the needs of a qualified persons with a disability.'' This language by its own terms recognizes the possibility that there may be situations where an appropriate placement may be in an institutional setting.

As to the comment on the separation of powers, the Department disagrees with the comment's assertion that its regulation removes political judgment from the hand of the States or supplants States' authority or discretion in this area. The Department is following the precedent set in the *Olmstead* decision. The regulation recognizes that, when States already have programs in place providing services to persons with disabilities, those programs must comply with two Federal civil rights requirements: section 504's and the ADA's requirement not to operate programs or activities in a manner that discriminates on the basis of disability. For reasons discussed elsewhere in our responses to comments about § 84.76 (d) (discussion of the ''at serious risk'' standard and the *U.S.* v. *Mississippi* decision) and the discussion of Executive Order 13132 and federalism, the rule's integration mandate, including the prohibition on failure to provide community-based services that results in ''serious risk of institutionalization,'' does not exceed statutory authority under section 504 and the ADA and therefore does not implicate separation of powers concerns by improperly intruding on State policymaking discretion.

Further, the rule requires only ''reasonable modifications,'' and codifies the ''fundamental alteration'' limitation, two additional features that respect the role of federalism.

Application (§ 84.76(a))

Comments: Several commenters asked the Department to clarify whether this section applies to specific programs, such as day programs for individuals with dementia or programs for individuals with mental illness. Additionally, some commenters asked for elaboration on how this applies to programs funded through Medicare Advantage. These commenters argued

[85] *See, e.g., Olmstead* v. *L.C.,* 527 U.S. 581 (1999); U.S. Dep't of Justice, Statement of the Department of Justice on Enforcement of the Integration Mandate of Title II of the Americans with Disabilities Act and *Olmstead* v. *L.C.* (2020), *https://www.ada.gov/olmstead/q&a_olmstead.htm.*

[86] *See e.g., Richard C. ex rel. Kathy B.* v. *Houstoun,* 196 FRD. 288, 292 (W.D. Pa. 1999) (''[I]t does not logically follow that institutionalization is required if any one of the three *Olmstead* criteria is not met.''); *Ball* v. *Kasich,* 520 F. Supp. 3d 979, 984–85 (S.D. Ohio 2021) (''These courts find that failure to provide facility-based services does not constitute discrimination under the ADA or Rehabilitation Act.'' *citing D.T.* v. *Armstrong,* 2017 U.S. Dist. LEXIS 91725 *20–21, 2017 WL 2590137 *7–8 (D. Idaho 2017)*, Sciarrillo* v. *Christie,* 2013 U.S. Dist. LEXIS 175178, 2013 WL 6586569, * 4 (D. N.J. Dec. 13, 2013) (citing *Richard S.* v. *Dep't of Developmental Servs. of the State of Cal.,* 2000 U.S. Dist. LEXIS 22750, 2000 WL 35944246, *3 (C.D. Cal. Mar. 27, 2000)); *Richard C. ex rel. Kathy B.* v. *Houstoun,* 196 FRD. 288, 292 (W.D. Pa. 1999); *Ill. League of Advocates for the Developmentally, Disabled* v. *Quinn,* 2013 U.S. Dist. LEXIS 86637, 2013 WL 3168758, *5 (N.D. Ill. June 20, 2013)).

that the failure to provide Medicaid and Medicare beneficiaries with needed services, including mental health services, treatments, and equipment, quickly leads to decreased health and function that can put both Medicaid and Medicare enrollees at serious risk of unnecessary institutionalization.

Response: The integration requirements apply to all programs or activities that receive Federal financial assistance from the Department without exception. The rule clarifies recipients' existing obligations under section 504 and does not create new obligations regarding integration. For example, managed care organizations and Medicare Advantage entities are obligated to provide services in the most integrated setting if doing so does not fundamentally alter the program or service. Similarly, hospital systems receiving Federal financial assistance from the Department must ensure their discharge planning processes facilitate HCBS when appropriate, rather than defaulting to coordinating placements for congregate care facilities.

We note that the ''most integrated setting'' depends on what is appropriate for the individual with a disability.

Comments: Several commenters highlighted the importance of the availability of key resources like accessible, affordable housing; transportation; and assistive technology, that individuals with disabilities need to engage fully in the community. Shortages in these programs and services create barriers to community integration. Commenters encouraged the Department to include access to these services in the rule.

Response: The Department agrees that many federally funded services are necessary to help eliminate barriers to community living and engagement. We note that this rule's coverage extends only to recipients of Federal financial assistance through this Department, and does not reach many transportation, housing, education, or other programs that do not receive HHS funds. However, we collaborate frequently with our Federal partners who do fund these services and have issued joint guidance about how these programs support community integration for disabilities.[87] We will consider additional joint guidance to advance coordination as appropriate.

Applicability of the Integration Requirement in a Public Health Emergency

Comments: Several commenters noted that Public Health Emergencies and natural disasters are critical junctures where people with disabilities are institutionalized. They cited the National Council on Disability (NCD) report, ''Preserving Our Freedom: Ending Institutionalization of People with Disabilities During and After Disasters,'' which found that people with disabilities are often transferred to nursing facilities or segregated shelters during emergencies, without proper assessment, transition planning or discharge planning.[88] Commenters highlighted that, during the COVID–19 pandemic, people were often placed in congregate care settings with extreme levels of uncontrolled infection and resulting high mortality rates.

Response: The Department has consistently stated that section 504 and other civil rights obligations apply during a public health emergency.[89] Further, even if a practice is allowed through an administrative policy such as a Public Health emergency waiver, such a waiver does not obviate the covered entity's responsibility to meet their obligations under section 504.

Obligations under the Medicare Program

Comments: Several commenters noted that the integration mandate has substantial implications for the Medicare program and requested that the Department clarify obligations of recipients operating Medicare-financed programs under section 504's integration mandate, including with respect to home health and other Medicare benefits.

Response: The Department agrees that section 504's integration mandate applies to Medicare programs, including Medicare Advantage plans, Medicare Part D plans, and other entities that receive Medicare funding (such as the Program of All-inclusive Care for the Elderly (PACE) programs or health plans operating under the Centers for Medicare & Medicaid Services' (CMS's) dual eligible demonstrations).

Discriminatory Action Prohibited (§ 84.76(b))

Comments: Several commenters found the phrasing ''unnecessary segregation,'' in § 84.76 (b), to be an extraneous and potentially confusing term. They expressed concern that the addition of the term may lead to the assumption that there is a second standard distinct from ''most integrated setting appropriate to the needs of a qualified person with a disability,'' that determines whether segregation is unnecessary. Other commenters objected to the proposed phrase, stating that segregation of people with disabilities is never necessary.

Response: Recipients have a longstanding, affirmative obligation under the integration requirement of section 504 to administer a program or activity ''in the most integrated setting appropriate to the needs of a qualified person with a disability.'' [90] Failing to do so may violate section 504. We appreciate comments that the second sentence may confuse recipients about the applicable standard. To clarify the requirements, we are deleting the second sentence. In doing so, the Department intends only to clarify the requirement of this section and does not mean to narrow the obligation to provide services in the most integrated setting appropriate to the needs of the individual with a disability.

Responses to Integration Question 1

Comments: In the discussion in the preamble of the proposed definition of ''most integrated setting,'' we solicited comments on whether the definition should be expanded. Many commenters from disability advocacy organizations suggested a definition: ''The most integrated setting is a setting that enables people with disabilities to live as much as possible like people without disabilities.'' Commenters said this definition was supported in a 2014 disability coalition statement ''Community Integration for People with Disabilities.'' [91] Commenters also suggested that this definition avoids imposing concrete secondary standards distinct from the ''most integrated setting,'' such as determining what is ''mainstream society.'' Some commenters also found the phrase

[87] *See e.g.,* U.S. Dep't of Health & Human Servs. & U.S. Dep't of Housing & Urban Dev., Fact Sheet: Advancing Community Living Through Coordination Between Housing and Voluntary Community Services (Dec. 8, 2021), *https://acl.gov/sites/default/files/ada/HHS-HUD_HousingFactSheetpdf.pdf.*

[88] Nat'l Council on Disability, *Preserving Our Freedom: Ending Institutionalization of People with Disabilities During and After Disasters,* (May 24, 2019), *https://ncd.gov/publications/2019/preserving-our-freedom.*

[89] *See* U.S. Dep't of Health & Human Servs., Off. for Civil Rts., FAQs for Healthcare Providers during the COVID–19 Public Health Emergency: Federal Civil Rights Protections for Individuals with Disabilities under Section 504 and Section 1557 (Feb. 4, 2022), *https://www.hhs.gov/civil-rights/for-providers/civilrights-covid19/disabilty-faqs/index.html;* U.S. Dep't of Health & Human Servs., Off. for Civil Rts., Bulletin: Civil Rights, HIPAA, and the Coronavirus Disease 2019 (COVID–19) (Mar. 28, 2020), *https://www.hhs.gov/sites/default/files/ocr-bulletin-3-28-20.pdf.*

[90] 45 CFR 84.4(b)(2).

[91] ADAPT et al., *Community Integration for People with Disabilities: Key Principles* (2014), *https://www.bazelon.org/wp-content/uploads/2017/10/Key-Principles.pdf* (stating that ''individuals with disabilities should have the opportunity to live like people without disabilities.'').

''mainstream society'' to be pejorative or biased against groups not identified as ''mainstream.''

Comments: Many commenters supported the importance of the individual's right to choose how and when they engage in the broader community. Some also emphasized the importance of informed choice, that an individual receives adequate information about available and programs and resources available to support services in the community.

Response: We appreciate the commenters' thoughtful responses to our request for comment on whether the definition of ''most integrated setting'' should be expanded, and we note disability advocacy groups' preference for a more streamlined definition. We have modified the NPRM's definition of ''most integrated setting'' to align more closely with the description of ''most integrated setting'' in title II *Olmstead* guidance.[92] To mirror the guidance, we are adding the clause ''these settings provide opportunities to live, work, and receive services in the greater community, like individuals without disabilities,'' to the definition published in the NPRM.

Segregated Settings (§ 84.76(c))

Comments: Several commenters objected to the use of the word ''unnecessarily'' in the rule's proposed language: ''A segregated setting is one in which people with disabilities are unnecessarily separated from people without disabilities,'' on the basis that segregation is inherently stigmatizing and thus never necessary. Many commenters emphasized that segregated settings are defined by a lack of informed, individual choice or autonomy for participants in how and when they interact with the broader community. These characteristics can be present even in settings such as group homes physically located in integrated communities.[93]

Many commenters suggested a paragraph describing segregated settings that provides features of segregated settings but is not a definitive list, in a style mirroring that of DOJ's *Olmstead* guidance.[94] Several commenters suggested that the definition include ''practices'' as well as ''policies,'' as the relevant restrictions or limitations on individual autonomy are not limited to those in formally adopted policies but also include those reflected in the setting's practices.

Response: We appreciate the robust comments on segregated settings. We agree that the list of qualities of segregated settings should be inclusive of examples, rather than defined by any one characteristic. We also agree that a covered entity's practices, in addition to its policies, can result in segregation. Accordingly, we revised § 84.76(c) by deleting the first sentence of the section. Paragraph (c) now provides that segregated settings include, but are not limited to, congregate settings populated exclusively or primarily with individuals with disabilities, and may be characterized by regimentation in daily activities, a lack of privacy or autonomy, or policies or practices limiting visitors or limiting individuals' ability to engage freely in community activities and to manage their own activities of daily living.

Relationship to Medicaid Statutes and Funding

Comments: Several commenters expressed concern that the integration mandate is perceived to conflict with the title XIX of the Social Security Act requirements. Title XIX requires Medicaid services be funded through an approved waiver or State plan program when the State elects to provide those services in the community instead of the mandatorily funded long-term care facilities, a requirement sometimes referred to as Medicaid's ''institutional bias.'' Other commenters raised concern about the need for increased Medicaid funding and rebalancing available Medicaid funds to prioritize community-based services. Some commenters asked that the definition of segregated settings mirror the CMS HCBS settings rule,[95] which sets the requirements for HCBS settings funded by Medicaid waivers. The Settings Rule lists several qualities of home and community-based settings, centered on rights of privacy, dignity and respect, and freedom from coercion and restraint, as well as promoting independence in making life choices, including but not limited to, daily activities, physical environment, and with whom to interact.

Response: As noted in the preamble to the NPRM, the civil rights obligations created by section 504 are separate and distinct from the requirements of Medicaid and the Social Security Act.[96] Compliance with Medicaid requirements does not necessarily mean a recipient has met the obligations of section 504. Further, implementation of title XIX or other Federal statutes is beyond the authority of this regulation to address.

Acknowledging comments desiring the same framework of ''integrated setting'' as the HCBS settings rule, we note that, while the HCBS settings rule can help States fulfill their obligations under section 504, a State's obligations under section 504 are independent of a State's compliance with the HCBS settings rule.[97]

Additionally, the Department appreciates commenters' feedback about the need for increased HCBS funding and rebalancing available Medicaid

[92] U.S. Dep't of Justice, Statement of the Department of Justice on Enforcement of the Integration Mandate of Title II of the Americans with Disabilities Act and *Olmstead* v. *L.C.* (2020), *https://www.ada.gov/olmstead/q&a_olmstead.htm* (last visited Feb. 21, 2024).

[93] *See, e.g., Pashby* v. *Delia,* 709 F.3d 307, 323 (4th Cir. 2013) (finding adult care homes institutional in nature and that the ''goals often fall short of reality'' of the facilities); *H.A. by L.A.* v. *Hochul,* 2022 WL 357213, at *6 (W.D.N.Y. 2022) (finding that engagement in community living activities misses the point that their schedules are circumscribed due to limited caregiver availability); *Murphy* v. *Harpstead,* 421 F. Supp. 3d 695, 716 (D. Minn. 2019) (community integration issues found when plaintiffs showed isolation, limited choice, and lesser quality of life in group homes than independent housing).

[94] U.S. Dep't of Justice, Statement of the Department of Justice on Enforcement of the Integration Mandate of Title II of the Americans with Disabilities Act and *Olmstead* v. *L.C.* (2020).

[95] Ctrs. for Medicare & Medicaid Servs., Medicaid Program; State Plan Home and Community-Based Services, 5-Year Period for Waivers, Provider Payment Reassignment, and Home and Community-Based Setting Requirements for Community First Choice and Home and Community-Based Services (HCBS) Waivers, 79 FR 2948 (Jan. 16, 2014).

[96] *See, e.g.,* U.S. Dep't of Health & Human Servs., Ctrs. for Medicare & Medicaid Servs, Instructions, Technical Guidance and Review Criteria: Application for a § 1915(c) Home and Community Based-Waiver, 15 (2019), *https://www.hhs.gov/guidance/sites/default/files/hhs-guidance-documents/instructions_technicalguide_v3.6_226.pdf* (''Although this is guidance with respect to the Medicaid program, we note that states have obligations pursuant to the Americans with Disabilities Act, section 504 of the Rehabilitation Act, and the Supreme Court's Olmstead decision interpreting the integration regulations of those statutes. Approval of any Medicaid Waiver action does not in any way address the State's independent obligations under the Americans with Disabilities Act or the Supreme Court's Olmstead decision.'').

[97] U.S. Dep't of Health & Human Servs., Ctrs. for Medicare & Medicaid Servs, Letter to State Medicaid Directors (Olmstead Update #4) (Jan. 10, 2001) (''. . . because Medicaid HCBS waivers affect the ability of States to use Medicaid to fulfill their obligations under the ADA and other statues, we have included these answers as an Olmstead/ADA update.'') *See, e.g.,* 88 FR 63486; and U.S. Dep't of Health & Human Servs., Ctrs. for Medicare & Medicaid Servs, Instructions, Technical Guidance and Review Criteria: Application for a § 1915(c) Home and Community Based-Waiver, 15 (2019), *https://www.hhs.gov/guidance/sites/default/files/hhsguidance-documents/instructions_technicalguide_v3.6_66.pdf* (''Although this is guidance with respect to the Medicaid program, we note that states have obligations pursuant to the Americans with Disabilities Act, section 504 of the Rehabilitation Act, and the Supreme Court's *Olmstead* decision interpreting the integration regulations of those statutes. Approval of any Medicaid Waiver action does not in any way address the State's independent obligations under the Americans with Disabilities Act or the Supreme Court's Olmstead decision.'').

funds to prioritize community-based services. However, these concerns are beyond the scope of the Department's rulemaking under section 504.

Specific Prohibitions (§ 84.76(d))

Comments: State officials objected to the proposed rule's inclusion in the list of specific prohibitions ''[f]ailure to provide community-based services that results in . . . serious risk of institutionalization'' (§ 84.76(d)(4)). These commenters cited the Fifth Circuit's decision in *United States* v. *Mississippi,* 82 F.4th 387 (5th Cir. 2023), to support their position. Commenters also took issue with the reference to DOJ's *Olmstead* guidance in the proposed rule's discussion of integration requirements. Several courts of appeals have found DOJ's *Olmstead* guidance to reflect the best reading of the statute and the then-applicable regulations,[98] whereas the Fifth Circuit declined to follow the guidance on the facts before it.[99]

Response: Based on the Supreme Court's decision in *Olmstead,*[100] decades of consensus in circuit courts, and the unambiguous requirements of existing title II and section 504 regulations, the Department affirms its decision to codify the ''at serious risk of institutionalization'' principle set forth in case law and guidance.

In the more than twenty years since *Olmstead,* courts have repeatedly held that individuals may bring nondiscrimination claims under section 504 and the ADA by showing a covered entity's actions place them at serious risk of unnecessary institutionalization. As noted in *Fisher* v. *Oklahoma,* the integration mandate's ''protections would be meaningless if plaintiffs were required to segregate themselves by entering an institution before they could challenge an allegedly discriminatory law or policy that threatens to force them into segregated isolation.'' [101] To this point, the title II and section 504 regulations create an unambiguous, affirmative obligation to *avoid* discrimination through unjustified isolation, as discussed below.

Thus, the overwhelming weight of authority supports robust protection for individuals at serious risk of unnecessary institutionalization. Of the seven circuits to consider the issue, the Fifth Circuit stands apart as the only one to question the long-standing application of ''serious risk'' in *Olmstead* cases.[102] Further, the Fifth Circuit did not reach the question of whether the other six circuits erred in their interpretations, noting that it ''need not say'' that the decisions of the other six circuits were ''wrong.'' [103] And even the Fifth Circuit did not definitively reject *Olmstead's* application to ''at risk'' cases in all circumstances. '' [104] The other circuits' at-risk decisions, by contrast, involved circumstances in which class-wide risks of institutionalization were ''susceptible of quantification and, indeed, generalization.'' [105] Despite some broadly worded *dicta,* the Fifth Circuit's liability holding in *Mississippi* ultimately rests on what the court saw as the breadth of the claim in that case.'' [106] The court favored a narrow reading in part because of the doctrine of ripeness.[107] That doctrine, which reflects Article III limitations on judicial power, is not relevant to the proper scope of the Department's regulations. That holding does not compel us to reject the longstanding principle, adopted by six other circuits, that a policy or practice that places individuals at serious risk of unnecessary institutionalization violates the integration mandate in appropriate cases.

The title II and section 504 regulations create an unambiguous, affirmative obligation to *avoid* discrimination through unjustified isolation. As legislatively authorized regulations, both carry the ''force and effect of law.'' [108] 28 CFR 35.130(d) requires that a ''public entity shall administer services, programs, and activities in the most integrated setting appropriate to the needs of qualified individuals with disabilities.'' The Department has long interpreted section 504 to impose the same requirement on recipients of Federal funding in 45 CFR 84.4(b)(2). Further, the regulation interpreting the reasonable modification component of title II, which is located at 28 CFR 35.130(b)(7)(i), requires public entities to ''avoid discrimination.'' Courts have held this creates a duty to address the risk of prohibited harm.[109] The proposed section 504 regulation, 45 CFR 84.68(d), adopts the same language, codifying the longstanding obligation under section 504. Mitigating serious risk of institutionalization is necessary to avoid discrimination in the form of unjustified isolation. In addition, it would still be appropriate for courts to grant injunctive relief to those at serious risk in order to prevent the unnecessary institutionalization prohibited by law. The potential scope of a judicial remedy only further highlights why it is appropriate for the Department to interpret section 504 to require recipients to avoid unnecessary institutionalization.[110]

Comments: Several commenters asked us to elaborate on the meaning of ''at serious risk,'' noting that courts have evaluated the risk of institutionalization for both probability of institutionalization and timing, to conclude that individuals at risk are likely to be institutionalized in the foreseeable future.

Response: We agree with commenters that the determination of ''serious risk'' is a fact-based inquiry, which is why the courts of appeals to have considered the question have provided only general guidance on determining risk rather than an exhaustive test.[111] Likewise, the Department declines to codify

[98] *See, e.g., Steimel* v. *Wernert,* 823 F.3d 902, 911 (7th Cir. 2016); *Davis* v. *Shah,* 821 F.3d 231, 263 (2d Cir. 2016); *Pashby* v. *Delia,* 709 F.3d 307, 322 (4th Cir. 2013).

[99] *United States* v. *Miss.,* 82 F.4th 387, 393–394 (5th Cir. 2023).

[100] *Olmstead* v. *L.C.,* 527 U.S. 581 (1999).

[101] Fisher v. Okla. Health Care Auth, 335 F.3d at 1181.

[102] *See Davis* v. *Shah,* 821 F.3d 231, 263 (2d Cir. 2016); *Pashby* v. *Delia,* 709 F.3d 307, 322 (4th Cir. 2013); *Waskul* v. *Washtenaw Cnty. Cmty. Mental Health,* 979 F.3d 426, 460–461 (6th Cir. 2020*); Steimel* v. *Wernert,* 823 F.3d 902, 914 (7th Cir. 2016); *Fisher* v. *Okla. Health Care Auth.,* 335 F.3d 1175, 1181–82 (10th Cir. 2003).

[103] U.S. v. Miss., 82 F.4th at 396.

[104] *Id.* at 392, 396.

[105] *Id.* at 396.

[106] *Id.* at 398.

[107] *Id.* at 397 (quoting *Waskul* v. *Washtenaw Cnty. Cmty. Mental Health,* 979 F.3d 426, 470 (6th Cir. 2020) (Readler, J. concurring in part and dissenting in part)).

[108] *See, e.g., Ramsay* v. *Nat'l Bd. of Med. Examiners,* 968 F.3d 251, 257 n.6 (3d Cir. 2020) (''The ADA authorizes DOJ to issue regulations implementing the public accommodations provisions of the ADA. Such regulations have the force and effect of law.'') (Internal quotation omitted).

[109] *See, e.g., Wisconsin Cmty. Servs., Inc.* v. *City of Milwaukee,* 465 F.3d 737, 753 (7th Cir. 2006) (''By requiring measures that are 'necessary to avoid discrimination on the basis of disability,' 28 CFR 35.130(b)(7), the regulation clearly contemplates that prophylactic steps must be taken to avoid discrimination.'').

[110] *See, e.g., United States* v. *W.T. Grant Co.,* 345 U.S. 629, 633 (1953) (explaining that ''[t]he purpose of an injunction is to prevent future violations'' and that such relief is appropriate where there is a ''cognizable danger of recurrent violation.'').

[111] For example, in *Davis* v. *Shah,* 821 F.3d 231, 262–63 (2d Cir. 2016), the court quoted DOJ: ''a plaintiff ''need not wait until the harm of institutionalization or segregation occurs or is imminent'' to bring a claim under the ADA. Plaintiff establishes a ''sufficient risk of institutionalization to make out an *Olmstead* violation if a public entity's failure to provide community services . . . will likely cause a decline in health, safety, or welfare that would lead to the individual's eventual placement in an institution.'' *See also, Waskul* v. *Washtenaw Cnty. Cmty. Mental Health,* 979 F.3d 426, 462 (6th Cir. 2020) finding ''declines in health, safety, or welfare'' as to sufficient to show plaintiffs were at serious risk of institutionalization.

parameters of the inquiry into ''serious risk.''

Comment: Several commenters argued the Department failed to adequately estimate the costs of integration provision as proposed in the Regulatory Impact Analysis, citing the Unfunded Mandates Reform Act (UMRA). Further, some State officials worried about the impact of the integration provision, specifically the ''at serious risk'' on States. Some commenters also asked that that the integration provision's implementation be delayed in order for States to plan for additional costs.

Response: The final integration provision codifies existing responsibilities for recipients, as explained in our responses to comments about § 84.76(d). Due to the existing nature of recipients' obligations, and the same preexisting obligations under title II for public entities, the final rule's integration provision places no additional costs on recipients. For the reasons discussed in that section, we find the ''at serious risk'' principle to be a well-established, central tenet of the integration requirement and part of enforcement of statutory rights that prohibit discrimination on the basis of disability. The rule is thus exempted from and not subject to the UMRA, from which Federal regulations that enforce statutory rights that prohibit discrimination on the basis of disability are exempted.[112]

Fundamental Alteration (§ 84.76(e))

Comments: In response to our request for comment on what may constitute a fundamental alteration for recipients who are not public entities, various commenters proposed that the creation or offering of a new service would be a fundamental alteration for non-public entities. Several commenters raised questions about what services a covered entity must provide to comply with this section, and whether entities, particularly private providers, would be required to create new services to support individuals in more integrated settings.

Response: We note that a recipient is not required to create ''new'' programs to assist people with disabilities, nor is it required to provide a particular standard of care or level of benefits. However, recipients must comply with section 504's nondiscrimination requirements—including the integration requirement—for the services they in fact provide. When a covered entity chooses to provide a service, it must do so in a nondiscriminatory fashion by ensuring access to that service in the most integrated setting appropriate to the needs of the qualified individual.[113]

Recipients may be required to offer services in an integrated setting that they have only been offering in segregated settings; that is generally not offering a ''new service,'' but instead is ensuring the service is offered in integrated settings and not just in segregated settings.[114] However, the expansion of a service to different settings or offering a substantially similar service may be a fundamental alteration. To the extent that a benefit, including an optional benefit, is already provided in institutions or other segregated settings as part of the recipient's program, the same or a substantially similar [115] benefit must be offered in an integrated setting in a manner that does not incentivize institutional or other segregated services over community services, unless extending the benefit would constitute a fundamental alteration of the program.

For example, if a managed care plan offers a Medicaid-funded respite care benefit through the temporary placement of an individual with a disability in an institutional setting, such as a nursing home or Intermediate Care Facility,[116] but does not offer a comparable respite benefit available in an individual with a disability's home, that would likely be prohibited discrimination under the rule, unless the plan could prove that adding a home-based benefit would be a fundamental alteration. Similarly, a hospital system that facilitates discharge planning to skilled nursing facilities but does not facilitate discharge planning for people with disabilities who wish to receive nursing services in their own home may constitute ''[a]dministering a program or activity that results in unnecessary segregation,'' which would violate § 84.76(b) of the final rule. This approach is consistent with the existing integration requirement under current case law, section 504, and title II of the ADA.[117]

Because what constitutes a ''fundamental alteration'' is fact-specific, the Department has not modified the proposed regulatory text.

Comments: Several commenters asked that the Department address the ''workforce crisis'' as a basis for a fundamental alteration defense. Commenters wrote that national workforce shortages among nursing staff and direct care workers create challenges for public and private providers. In addition, commenters noted that State budgetary decisions constrain public and private providers in their ability to offer services, recruit and retain staff, and otherwise provide services to all eligible individuals with disabilities, noting that available funds and reimbursement rates may be beyond the control of individual providers or networks. Commenters also asked that OCR make explicit that a determination of whether something constitutes a fundamental alteration is fact and context-specific. Some commenters asked for an explanation of how an ''effectively working'' *Olmstead* plan could show that a requested modification would require fundamental alteration of the covered entity's existing programs or services.

Response: States and other recipients cannot dismiss their obligation to provide community services on the basis that services may require changes to the recipients' methods of administration. Reimbursement rates, direct workforce pay rates, and network adequacy are ''methods of administration'' under § 84.68(b)(3) as well as ''planning, service system design, funding, or service implementation practices'' under § 84.76(d)(4). A recipient might be in violation of this section if it adopts reimbursement practices or other

[112] 2 U.S.C. 1503(2).

[113] *See Olmstead* v. *L.C.,* 527 U.S. at 603; *see also Radaszewski* v. *Maram,* 383 F.3d 599, 609 (7th Cir. 2004) (citing *Olmstead* v. *L.C.,* 527 U.S. at 603 n. 14, for the principle ''that States must adhere to the ADA's nondiscrimination requirement with regard to the services they in fact provide'') (''While 'a State is not obligated to create new services,' it 'may violate Title II when it refuses to provide an existing benefit to a disabled person that would enable that individual to live in a more community-integrated setting.' '').

[114] *See* U.S. Dep't of Justice, Civil Rights Div., Statement of the Department of Justice on Enforcement of the Integration Mandate of Title II of the Americans with Disabilities Act and *Olmstead* v. *L.C.,* Question 8 (June 22, 2011), *https://archive.ada.gov/olmstead/q&a_olmstead.htm (stating that* (p)ublic entities cannot avoid their obligations under the ADA and *Olmstead* by characterizing as a ''new service'' services that they currently offer only in institutional settings.). *See also Townsend* v. *Quasim,* 328 F.3d 511, 517 (9th Cir. 2003) (''Here, the precise issue is not whether the state must provide the long term care services sought by Mr. Townsend and the class members—the state is already providing these services—but in what location these services will be provided.'').

[115] A substantially similar service is one that is similar in substance to the institutional service, even if the service ''might vary in format depending on whether it is provided . . . in an institution or a community-based setting.'' *Radaszewski ex. rel. Radaszewski* v. *Maram,* 383 F.3d 599, 610 (7th Cir. 2004).

[116] Please note, these are facilities that require an individual to meet eligibility requirements for a certain level of care for admission.

[117] *See, e.g.,* U.S. Dep't of Justice, Statement of the Department of Justice on Enforcement of the Integration Mandate of Title II of the Americans with Disabilities Act and *Olmstead* v. *L.C.,* Question 8 (2020), *https://www.ada.gov/olmstead/q&a_olmstead.htm; Steimel* v. *Wernert,* 823 F.3d 902, 914 (7th Cir. 2016).

methods of administration that result in individuals with disabilities only being able to receive residential, employment, day habilitation, or other necessary support services in segregated settings.[118]

We restate that fundamental alteration is a fact-specific inquiry and that increased cost alone is not necessarily a fundamental alteration.[119] Further, we note that cost and reimbursement decisions may be made by multiple entities, including State agencies, managed care plans, and private providers. As the Department noted in the proposed rule for section 1557, 87 FR 47873, recipients taking on financial risk for the delivery of HHS-funded services should scrutinize their capitation, reimbursement, quality measurement, and incentive structures to ensure that they do not result in the unjustified segregation of individuals with disabilities or place individuals with disabilities at serious risk of institutionalization or segregation. Under circumstances where responsibility for segregated and integrated services is shared across multiple entities, for example, under a managed care contract, both the State Medicaid agency and the contracted entity have obligations under this provision if they are both recipients of Federal financial assistance.

This shared responsibility means, for example, that recipients cannot assert that a staffing shortage, in and of itself, demonstrates that provision of services would be a fundamental alteration. If the recipient can address staffing shortages through pay rates, recruitment and retention incentives, flexible scheduling such as split shifts, or other actions, it may be required to do so as a reasonable modification.[120]

The availability of the fundamental alteration defense is clear as drafted and so we decline to change the language in the regulation text. In this final rule, we clarify a program is not required to provide coverage for a service in the most integrated setting appropriate to an individual's needs if it would fundamentally alter the program to do so.

Technical Assistance

Comments: Several commenters requested the Department provide technical assistance addressing the differences between compliance with Medicaid and adherence to civil rights laws, with practical examples and best practices. Other commenters suggested that the Department provide additional guidance to recipients on how the integration provision applies to transitions in care and effective community-based supports for those discharged from hospitals, skilled nursing facilities, and other institutional settings. Additionally, a few commenters recommended the Department offer technical assistance on how this regulation will address unfair practices in system design and funding.

Response: We appreciate the comments requesting clarification through sub-regulatory guidance. We will consider future guidance after this rule has been finalized and remain committed to our continued partnership with DOJ and CMS in developing shared guidance on civil rights requirements.

Summary of Regulatory Changes

For the reasons set forth above and considering comments received, we are revising § 84.76(b) and (c). Paragraph (b) requires a recipient to administer a program or activity in the most integrated setting appropriate to the needs of a qualified person with a disability. Paragraph (c) discusses integrated settings as settings that include (but are not limited to) congregate settings that are populated exclusively or primarily with individuals with disabilities, and may be characterized by regimentation in daily activities, lack of privacy or autonomy, or policies or practices limiting visitors or limiting individuals' ability to engage freely in community activities and to manage their own activities of daily living.

Subpart H—Communications

Proposed subpart H addressed requirements related to providing effective communication for individuals with disabilities. The Department requested comment on the importance of providing information in plain language for individuals with cognitive, developmental, intellectual, or neurological disabilities. Additionally, the Department requested comment on whether plain language is appropriately considered a reasonable modification that an individual must request, or if it should be considered an auxiliary aid or service.

The proposed requirements of this subpart are nearly identical to the requirements of subpart E, Communications, in the ADA title II regulations.[121]

General (§ 84.77)

Proposed § 84.77(a)(1) required recipients to take appropriate steps to ensure that communications with individuals with disabilities, and companions with disabilities, are as effective as communications with individuals without disabilities.

Proposed § 84.77(1)(2) defined ''companion.''

Proposed § 84.77(b)(1) required recipients to provide appropriate auxiliary aids and services to individuals with disabilities where necessary to afford those individuals an equal opportunity to benefit from the recipient's program or activity. Proposed § 84.77(b)(2) provided criteria for determining which auxiliary aid is appropriate. It stated that in order for auxiliary aids to be effective, they must be provided in accessible formats, in a timely manner, and in such a way as to protect the privacy and independence of the individual with a disability.

Proposed § 84.77(c) provided specifics regarding interpreters. It stated that recipients cannot require an individual with a disability to bring another individual to interpret. Nor can a recipient rely on an adult accompanying an individual with a disability to interpret or facilitate communication except in an emergency or when an individual with a disability specifically requests that the adult interpret, the adult agrees, and reliance on the adult is appropriate. Minor children cannot interpret except in an emergency when there is an imminent threat and no interpreter is available.

Proposed § 84.77(d) set forth specific standards that a recipient must meet if it chooses to provide qualified interpreters via video remote interpreting services.

The comments and our responses regarding § 84.77 are set forth below.

[118] Public entities may raise a fundamental alteration defense by showing that they have developed, and are implementing, a comprehensive, effectively working *Olmstead* plan. To avail themselves of such a defense, the entity's plan must have specific and reasonable timeframes and measurable goals for which the public entity may be held accountable, and the plan must have demonstrated success in actually moving individuals to integrated settings in accordance with the plan. *See, e.g., Brown* v. *District of Columbia,* 928 F.3d 1070, 1084 (D.C. Cir. 2019); *Frederick L.* v. *Dep't of Pub. Welfare,* 422 F.3d 151, 157 (3d Cir. 2005); *Jensen* v. *Minn. Dep't of Human Servs.,* 138 F. Supp. 3d 1068, 1072 (D. Minn. 2015).

[119] *Fisher* v. *Okla. Health Care Auth.,* 335 F.3d 1175, 1183 (10th Cir. 2003).

[120] *See United States* v. *Fla.,* No. 12–CV–60460, 2023 WL 4546188, at *59 (S.D. Fla. July 14, 2023) (requiring Florida to increase private duty nursing services for medically fragile children and requiring the State to address the shortage of nurses ''by requiring that managed care plans raise PDN reimbursement rates, ensuring that the managed care plans comply with network adequacy standards, or utilizing any other tool at its disposal.'') (under appeal in *United States* v. *Florida,* No. 23–12331 (11th Cir.)

[121] 28 CFR 35.160 through 35.164.

Comment: Almost all of the commenters supported ensuring that recipients communicate effectively with people with disabilities. Disability rights organizations, recipient organizations, and individuals acknowledged that in the absence of appropriate auxiliary aids and services, people with disabilities are denied access to recipient programs and activities, including health care.

Response: The Department agrees that effective communication with people with disabilities is a critical right that benefits members of the public and recipients. The provision of sign language interpreters, Braille documents, and other appropriate auxiliary aids and services helps people with disabilities fully participate in and enjoy the benefits of recipient programs and activities from which they would otherwise be excluded on the basis of their disability. The importance of effective communication cannot be overstated in the context of health and human services, which is why the Department proposed the updates in subpart H of this rulemaking.

Comment: Many commenters described the importance of effective communication and provided firsthand accounts of instances where they were unable to receive health care because recipients did not provide them with auxiliary aids or services or reasonable modifications. For example, commenters relayed instances where American Sign Language interpreters were not provided even after a patient request, information was not provided in plain language for people with intellectual disabilities, and staff denied patients appropriate auxiliary aids and services due to appointment time constraints. Many of these commenters also discussed the importance of providing effective communication for companions.

Response: Unfortunately, the Department is aware of many instances where people with disabilities were discriminated against because recipients denied them effective communication. The Department has investigated and resolved many such instances and is aware that other Federal agencies have done likewise.[122] The Department and other Federal agencies have issued numerous guidance documents to attempt to further educate recipients on their effective communication responsibilities.[123] The Department added subpart H to the proposed rule because despite existing communication requirements for people with disabilities, it is apparent that some recipients are not providing effective communication to people with disabilities.

Comment: The majority of the commenters voiced support for requiring that all recipients, regardless of employee size, provide appropriate auxiliary aids and services to people with disabilities. Previously, § 84.52(d)(2) only required recipients with fewer than fifteen employees to provide auxiliary aids and services when the Director of OCR required those recipients to do so. Commenters stated that advancements in technology have made auxiliary aids and services affordable and attainable for recipients regardless of their size, eliminating the need for any exception. Those commenters also stated that the absence of appropriate auxiliary aids and services among small health care practices leads to disproportionate harm to patients with disabilities who are denied health care. One commenter requested that the Department maintain an exception for recipients with fewer than fifteen employees due to concerns that providing appropriate auxiliary aids and services would be too costly for small recipients.

Response: The Department agrees with the majority of commenters that effective communication is critical for people with disabilities, and that harm from a denial of effective communication for a person with a disability is the same regardless of the size of a recipient. Additionally, the Department expects that auxiliary aids and services are affordable and attainable for many recipients. All recipients, regardless of size, are not required, in providing effective communication, to take any action that the recipient can demonstrate would result in a fundamental alteration to the program or activity or pose undue financial and administrative burdens. In addition, the vast majority of recipients of Federal financial assistance from the Department are already required by either title II or title III of the ADA to provide auxiliary aids or services in order to ensure effective communication. Further, on December 19, 2000, the Department issued a notice in the **Federal Register** that it was exercising its authority under § 84.52(d)(2) to require recipients with fewer than fifteen employees to provide auxiliary aids to individuals with disabilities where the provision of such aids would not significantly impair the ability of the recipient to provide its benefits or services.[124] Accordingly, recipients with fewer than fifteen employees have been on notice since December of 2000 that the Department interprets section 504 to require all recipients, regardless of size, to provide appropriate auxiliary aids and services. The Department is incorporating this obligation to provide appropriate auxiliary aids and services in the final rule.

Plain Language

Comment: Many individuals and organizations submitted comments on the importance of providing plain language in health and human service programs and activities. Many commenters stated that plain language is a necessity that benefits all individuals, regardless of whether they have a disability. Some commenters stated that other groups, including individuals with limited English proficiency and people with lower education levels, would also benefit from the increased use of plain language. Through plain language, people with disabilities will have a better understanding of the services they are eligible for and may even be able to avoid unnecessary outcomes such as guardianships or the removal of children. Some commenters stated that plain language alone will not ensure effective communication for all people with disabilities and asked the Department to also require that recipients provide information through other means, such as audio or visual versions of certain standard language.

Response: The Department agrees that plain language may benefit individuals seeking to access a recipient's programs and activities, including individuals with disabilities. The Department also agrees that plain language alone will not be sufficient to ensure effective communication for people with disabilities in all circumstances, including for some people with intellectual or developmental disabilities. This Communications subpart provides detailed measures that

[122] *See e.g.,* U.S. Dep't of Health & Human Servs., Off. for Civil Rights, HHS Office for Civil Rights Takes Action to Ensure Effective Communication for Those Who Are Deaf or Hard of Hearing (Nov. 9, 2022), *https://www.hhs.gov/about/news/2022/11/09/hhs-office-for-civil-rights-takes-action-to-ensure-effective-communication-for-those-who-are-deaf-or-hard-of-hearing.html;* U.S. Dep't of Justice, Justice Department Secures Agreement with Hospital to Ensure Effective Communication with Deaf Patients and Companions (Jan. 4, 2022), *https://www.justice.gov/opa/pr/justice-department-secures-agreement-hospital-ensure-effective-communication-deaf-patients.*

[123] *See* U.S. Dep't of Health & Human Servs., Off. for Civil Rights, Disability Resources for Effective Communication, *https://www.hhs.gov/civil-rights/for-individuals/special-topics/hospitals-effective-communication/disability-resources-effective-communication/index.html.*

[124] 65 FR 79368 (Dec. 19, 2000).

should be taken to ensure effective communication for individuals with disabilities.

Comment: Many commenters recommended that the Department emphasize that plain language is a reasonable modification that can be made available to people with disabilities upon request when necessary to avoid discrimination. These commenters reasoned that while plain language may be vitally important for people with certain disabilities to understand important health or human service information, it will not be necessary or even beneficial in every circumstance. Alternatively, many commenters recommended that the Department specify that plain language is an auxiliary aid that a recipient must provide, when appropriate, to ensure effective communication for people with disabilities. One commenter stated that plain language should only be a recommended best practice and should not be an auxiliary aid or reasonable modification under this rulemaking because of the cost for recipients. One commenter recommended requiring specific standards to define plain language. Finally, some commenters requested additional technical assistance and guidance from the Department on what constitutes plain language and what recipients are required to provide to people with disabilities.

Response: As noted in the preamble to the NPRM, and consistent with title II of the ADA, providing information in plain language under some circumstances may be a reasonable modification a recipient may have to provide to avoid discrimination. It may also be a strategy recipients could use to improve their communications with people with disabilities. The Department appreciates the range of comments on this important issue and recognizes there are benefits and limitations to both methods of characterization.

Because of the wide range of situations in which the need for plain language could arise, the Department wants to preserve flexibility for both individuals with disabilities and recipients while limiting burdens. The Department notes that the effective communication provision of § 84.77(a)(1) requires recipients to take steps to ensure that their communications with individuals with disabilities are ''as effective as'' communications with others. In addition, reasonable modifications in § 84.68(b)(7)(i) are required when necessary to avoid discrimination on the basis of disability. Whether plain language is a reasonable modification in any given case will depend on particular facts, including the cost to the recipient of providing plain language materials or information. Because plain language may already be required by other provisions, including § 84.68(b)(7)(i), the Department declines to adopt any additional regulatory text on plain language. Accordingly, the Department will retain the current language in the preamble to the proposed rule that states plain language may be a reasonable modification to help ensure effective communication for people with disabilities.

Augmentative and Alternative Communication

Comment: Several commenters discussed augmentative and alternative communication (AAC) devices and voiced support for their inclusion in the rulemaking. Most of those commenters agreed that AAC may be an auxiliary aid or service to ensure effective communication for people with certain disabilities. Some also stated the Department should alter the definition of auxiliary aids and services to explicitly include AAC. Similarly, some commenters thought that the Department should provide a comprehensive definition of AAC in the rulemaking. One commenter stated a belief that the rulemaking should require recipients to provide training on the use of AAC devices for people with disabilities. One commenter stated that AAC may be a reasonable modification to provide effective communication.

Response: The Department appreciates the support for inclusion of language on AAC in the rulemaking and agrees that AAC may be an effective method for people with certain disabilities to communicate with recipients. The preamble to this section in the proposed rule noted that the definition for auxiliary aids and services is open-ended and allows for AAC as an appropriate auxiliary aid or service when necessary to ensure effective communication for people with disabilities. Because of this definition for auxiliary aids and services, it is not necessary at this time to edit the definition of auxiliary aids and services to explicitly include AAC, or to provide an extensive definition of AAC. The definition of auxiliary aids and services is purposefully drafted to ensure that it is inclusive of unnamed services and actions that provide effective communication. Whether training on the use of AAC devices would be a reasonable modification to policies, practices, or procedures, as required by this rulemaking, depends on specific facts.

Comment: One commenter recommended specific minor edits to the language of subpart H to make communication requirements more expansive and clarify how they apply to people with a variety of disabilities. Similarly, some commenters requested additional examples be added to the list of auxiliary aids and services, additional standards for measuring effective communication, and additional general requirements for communication with people with disabilities.

Response: The Department appreciates the recommendations from commenters concerning additional edits to effective communication requirements and the definition of auxiliary aids and services. We acknowledge the recommendations for additions to the language of the regulatory text for additional instances that would amount to effective communication or provide clarity that certain auxiliary aids and services are covered by the rulemaking, but we decline to incorporate the suggested changes. The current definition of auxiliary aids and services already adequately covers the recommendations from the commenters. The definition of ''auxiliary aids and services'' in the definitions section at § 84.10 contains a phrase that says that auxiliary aids and services include ''other similar services and actions.'' The current definition allows for additional auxiliary aids not contained in the preceding lists. We will retain the proposed language, which aligns with the communication requirements of the regulations under title II of the ADA.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.77 as proposed with no modifications.

Telecommunications (§ 84.78)

Proposed § 84.78 set forth the requirements that a recipient must meet when it communicates with applicants and beneficiaries by telephone or an automated-attendant system. Proposed § 84.78(a) stated that when a recipient communicates by telephone, text telephones (TTYs) or equally effective telecommunications systems shall be used to communicate with individuals who are deaf or hard of hearing or have speech impairments.

Proposed § 84.78(b) stated that when an automated-attendant system is used, that system must provide effective real-time communication with individuals using auxiliary aids and services.

Proposed § 84.78(c) stated that a recipient shall respond to telephone calls from a telecommunications relay service established under title IV of the ADA in the same manner that it responds to other telephone calls.

Comment: An organization that represents individuals with disabilities said that they appreciated the requirement in § 84.78(b) that when a recipient uses an automated-attendant system, real-time communication must be provided. However, they asked us to underscore that when using such a system, individuals must be able to opt out of the system and speak with a live representative.

Response: The Department appreciates the commenters' feedback. In order to be consistent with the title II ADA regulations, we decline to add any requirements to this section. However, we strongly urge recipients to have a way to communicate with a live person when using automated-attendant systems.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.78 as proposed with no modifications.

Telephone Emergency Services (§ 84.79)

Proposed § 84.79 stated that telephone emergency services must provide direct access to individuals who use TTYs and computer modems.

Comment: The Department received some comments supportive of this section. One commenter suggested that, in addition to 911, the section should refer to 988 which is the national suicide and crisis hotline.

Response: The Department appreciates the commenter's suggestion. However, there are other hotlines funded by the Department that also could potentially be listed by name in addition to the regulatory reference to telephone emergency services. Any such list could quickly become outdated and could cause confusion if inconsistent with the analogous provision of the regulation implementing title II of the ADA. Rather than list every hotline, the Department will keep the section as written.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.79 as proposed with no modifications.

Information and Signage (§ 84.80)

Proposed § 84.80(a) stated that recipients must ensure that interested persons including those with impaired vision or hearing can obtain information as to existence and location of accessible services, activities, and facilities. Section 84.80(b) stated that recipients must provide signage at all inaccessible entrances directing users to an accessible entrance or to a location where they can obtain information about accessible facilities. The international symbol for accessibility must be used at each accessible entrance of a facility.

Comments: The Department received a few comments on this section. One commenter asked that the section include a reference to individuals with language disorders such as aphasia. Another commenter asked whether the information and signage requirements apply to recipients' facilities that are not open to the public. The commenter noted the challenges of securing in-person Certified Deaf Interpreters and problems with relying on TTY State-operated phone lines.

Response: With regard to the request that we add language disorders to the text of the section, we note that coverage is not limited to individuals with impaired vision or hearing. The section requires that recipients ensure that all interested persons, *including* those with impaired vision or hearing, can obtain the information. We decline to add the requested language since the section already covers individuals with language disorders.

In response to the commenter's question about where signage must be placed, the requirement applies to all inaccessible entrances to each of a recipient's facilities. The Department recognizes the challenges that may be involved in complying with the regulations and notes that § 84.81 sets forth the duties of recipients when an action would result in a fundamental alteration or undue financial and administrative burdens.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.80 as proposed with no modifications.

Duties (§ 84.81)

Proposed § 84.81 stated that subpart H does not require recipients to take an action that would result in a fundamental alteration in the nature of a program or activity or undue financial and administrative burdens. It sets forth details about how that determination is to be made.

The comments and our responses regarding § 84.81 are set forth below.

Comment: Many recipient organizations voiced their support for the proposed exceptions concerning fundamental alteration or undue administrative and financial burdens. Recipient organizations noted that some small providers may find it difficult to pay for auxiliary aids and services and may rely on the exceptions. Many recipient organizations also requested that the Department provide additional guidance on instances where providing auxiliary aids or services would result in a fundamental alteration or undue burden. Some recipient organizations also requested that the Department provide additional funding or establish resource centers to provide auxiliary aids or services on behalf of recipients.

Response: As the commenters note, under proposed § 84.81, recipients would not be required to provide specific auxiliary aids or services, or take a specific action to ensure effective communication, if doing so would result in a fundamental alteration in the nature of a program or activity or in undue financial and administrative burdens. However, a recipient would still be required to take any other action that would not result in such an alteration or such burdens while providing effective communication to the maximum extent possible. For example, even if one type of auxiliary aid or service requested by the person with a disability would result in a fundamental alteration of the program or activity in question, if another appropriate auxiliary aid or service exists that would assist effective communication without fundamentally altering the program or activity, the recipient is required to offer that other auxiliary aid or service.

Effective communication, including provision of auxiliary aids and services, has been required for decades by the original section 504 implementing regulation, titles II and III of the ADA, and more recently the implementing regulation for section 1557 of the ACA, and numerous guidance documents on the topic already exist.[125] The Department remains committed to providing technical assistance and education to help recipients understand their legal obligations and so that individuals understand their rights.

[125] *See* U.S. Dep't of Justice, ADA Requirements: Effective Communication (Feb. 28, 2020), *https://www.ada.gov/resources/effective-communication/#auxiliary-aids-and-services;* U.S. Dep't of Health & Human Servs., Off. for Civil Rights, Disability Resources for Effective Communication, *https://www.hhs.gov/civil-rights/for-individuals/special-topics/hospitals-effective-communication/disability-resources-effective-communication/index.html.*

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.81 as proposed without modifications.

Subpart I—Web, Mobile, and Kiosk Accessibility [126]

Proposed subpart I addressed requirements related to providing accessible web content, mobile applications, and kiosks.

The Department proposed to add six definitions relevant to this subpart to the Definitions section in the newly redesignated § 84.10. We invited comment on the following questions regarding the definitions:

- *Web Accessibility Question 1:* The Department's definition of ''conventional electronic documents'' consists of an exhaustive list of specific file types. Should the Department instead craft a more flexible definition that generally describes the types of documents that are covered or otherwise change the proposed definition, such as by including other file types (*e.g.,* images or movies), or removing some of the listed file types?
- *Web Accessibility Question 2:* The Department requests comment on whether a definition of ''kiosks'' is necessary, and if so, requests comment on the Department's proposed definition in § 84.10 and any suggested revisions to it.
- *Web Accessibility Question 3:* Are there refinements to the definition of ''web content'' the Department should consider? Consider, for example, WCAG 2.1's definition of ''web content'' as ''information and sensory experience to be communicated to the user by means of a user agent, including code or markup that defines the content's structure, presentation, and interactions.'' [127]

The comments and responses regarding the definitions are set forth below.

Comment: Many commenters stated that the proposed definition of ''conventional electronic documents'' should be non-exhaustive to allow for broader application, such as other video, audio, image, spreadsheet, data files, and new content that has not yet been developed. Some commenters objected to the possibility of an open-ended definition and prefer the proposed definition the Department provided because they are concerned that allowing too much flexibility will lead to confusion among recipients and the general public as to what is covered.

Some commenters opposed the inclusion of ''database file formats'' in the definition of conventional electronic documents because database files and some spreadsheet files may include data that are not primarily intended to be human-readable. The commenters stated that in many cases such content is intended to be opened and analyzed with other special software tools and that data that is not primarily intended to be human-readable is equally accessible for individuals with disabilities and individuals without disabilities.

Response: The Department declines to change its approach to defining conventional electronic documents. The Department expects that a more flexible definition would result in less predictability for both recipients and individuals with disabilities, especially because the Department does not currently have sufficient information about how technology will develop in the future. The Department seeks to avoid such uncertainty because the definition of conventional electronic documents sets the scope of two exceptions, § 84.85(b) and (d). The Department carefully balanced benefits for individuals with disabilities with the challenges recipients face in making their web content and mobile apps accessible in compliance with this final rule when crafting these exceptions, and the Department does not want to inadvertently expand or narrow the exceptions with a less predictable definition of conventional electronic documents.

Based on the comments received, the Department has decided to delete database file formats from the definition of conventional electronic documents. Database files may be less commonly available through recipients' web content and mobile apps than other types of documents. To the extent that such files are provided or made available by recipients, the Department understands that they would not be readable by either individuals with disabilities or individuals without disabilities if they only contain data that are not primarily intended to be human-readable. Therefore, there would be limited accessibility concerns, if any, that fall within the scope of the rule associated with documents that contain data that are not primarily intended to be human-readable. Accordingly, the Department believes it could be confusing to include database file formats in the definition. However, the Department notes that while there may be limited accessibility concerns, if any, related to database files containing data that are not primarily intended to be human-readable, recipients may utilize these data to create outputs for web content or mobile apps, such as tables, charts, or graphs posted on a web page, and those outputs would be covered by the rule unless they fall into another exception.

The Department declines to make additional changes to the list of file formats included in the definition of conventional electronic documents. After reviewing the range of different views expressed by commenters, the Department believes the current list strikes the appropriate balance between ensuring access for people with disabilities and feasibility for recipients so that they can comply with this rule. The list included in the definition is also aligned with the Department's intention to cover documents that recipients commonly make available in either an electronic form or that would have been traditionally available as physical printed output. If recipients provide and make available files in formats not included in the definition, the Department notes that those other files may qualify for the exception in § 84.85(a) if they meet the definition for archived web content, or the exception in § 84.85(e) for certain preexisting social media posts if they are covered by that exception's description. To the extent those other files are not covered by one of the exceptions in § 84.85, the Department also notes that recipients would not be required to make changes to those files that would result in a fundamental alteration in the nature of a program or activity, or impose undue financial and administrative burdens, consistent with § 84.88.

Comment: Regarding the definition of ''kiosks,'' many commenters stated that they support a broad definition of kiosks that goes beyond the Department's proposed definition. Specifically, some commenters stated that anything with a user interface in a health care setting should be considered a kiosk. Other commenters proposed including a variety of physical devices that provide

[126] The Department of Justice recently promulgated new regulations implementing title II of the ADA to establish specific requirements, including the adoption of specific technical standards, for making accessible the web content and mobile apps that public entities provide or make available. *See* regulation to be codified at 28 CFR part 35, subpart H. The Department has made every effort to align its regulations on the accessibility standards in subpart I with DOJ's regulations, to maximize consistency in the obligations for web and mobile apps for recipients covered under section 504 and public entities covered under title II. Please refer to DOJ's rule, including Appendix D to the regulation implementing title II, for additional guidance related to this subpart.

[127] W3C®, *Web Content Accessibility Guidelines 2.1* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A–GG2F.*

a variety of services through both closed and open functionality.

Response: The comments received covered a wide range of responses on definitions for kiosks. We note that the Access Board is currently engaged in the early stages of rulemaking around self-service transaction machines and self-service kiosks.[128] In part because of the wide range of responses that generally do not agree on a single definition, the Department does not believe it is appropriate to make changes to the definition of kiosks in this rulemaking. A broader definition of kiosks runs the risk of overclassifying devices used in a health or human services setting as a kiosk, while identifying specific types of physical devices could leave out devices that otherwise perform all of the functions normally attributed to kiosks. Because of the range of comments received, and because the Access Board is currently working towards addressing this issue in its own rulemaking, the Department will finalize its definition of kiosks in this rule without change from the proposed rule. Once the Access Board has finalized its rulemaking, the Department may consider addressing any additional issues raised with the Access Board's guidelines.

Comment: Regarding the definition of ''web content,'' some commenters opined that the definition should more closely align with the definition included in WCAG 2.1, especially since the proposed rule would include WCAG 2.1. Some of those commenters stated that a different definition would cause confusion among technical experts.

One commenter expressed approval of the proposed definition while another requested general clarification of what is covered and what specific content will have to be accessible under the proposed rule.

Response: The Department appreciates the comments and has decided to alter the definition of web content to more closely align with the definition in WCAG 2.1. The Department's definition in the NPRM was based on the WCAG 2.1 definition but was slightly less technical and intended to be more easily understood by the public generally. The Department decided to align the definition of ''web content'' with the definition in WCAG 2.1 in the final rule to avoid confusion, ensure consistency in application of WCAG 2.1, and assist technical experts in implementing this rule. Consistent with the suggestion of commenters, the Department believes this approach minimizes possible inadvertent conflicts between the type of content covered by the Department's regulatory text and the content covered by WCAG 2.1. Accordingly, the Department will use the WCAG 2.1 definition but also include the specific examples in a second sentence. This second sentence may be particularly useful for members of the public without a technical background.

Beyond the definition provided, as well as the preamble language explaining the definition, the Department remains committed to providing technical assistance and guidance to recipients so that they are able to fully comply with this rule. We also note that there is a period for recipients to become familiar with the web content compliance obligations before they come into effect, which will be two or three years depending on the size of the recipient.

The Department also added a definition for ''user agent.'' The definition exactly matches the definition of user agent in WCAG 2.1.[129] WCAG 2.1 includes an accompanying illustration, which clarifies that the definition of user agent means ''[w]eb browsers, media players, plug-ins, and other programs—including assistive technologies—that help in retrieving, rendering, and interacting with web content.'' [130]

The Department added this definition to the final rule to ensure clarity of the term ''user agent,'' which appears in the definition of ''web content'' requested by commenters and now adopted by the Department. As discussed, the Department has more closely aligned the definition of ''web content'' in the final rule with the definition in WCAG 2.1. Because this change introduced the term ''user agent'' into the section 504 regulation, and the Department does not believe this is a commonly understood term, the Department has added the definition of ''user agent'' provided in WCAG 2.1 to the final rule. The Department also believes adding this definition in the final rule is consistent with the suggestions of commenters who proposed aligning the definition of ''web content'' with the definition in WCAG 2.1.

Accordingly, we are finalizing the definition of ''kiosks'' with no modifications, editing ''conventional electronic documents'' and ''web content,'' and adding the definition of ''user agent,'' in § 84.10. As further discussed in the preamble to subpart A and § 84.85(a), we are also revising the definition of ''archived web content.''

Application (§ 84.82)

Proposed § 84.82 stated that this subpart applies to all programs and activities that receive Federal financial assistance from the Department.

The Department is finalizing § 84.82 as proposed.

Accessibility of Kiosks (§ 84.83)

Proposed § 84.83 articulated a general nondiscrimination requirement for programs and activities provided through kiosks.

The comments and our responses regarding § 84.83 are set forth below.

Comment: Many commenters expressed support for the inclusion of kiosks in the proposed rule, noting that kiosks have become more prevalent in health care settings and that often these kiosks are not accessible for people with disabilities. Many of these same commenters stated that the Department should require specific accessibility standards for kiosks beyond the general accessibility requirement proposed. Some commenters proposed specific functional standards that they believe are important for kiosk accessibility. Some commenters expressed approval of allowing for recipients to provide alternate methods for people with disabilities to access the programs and activities typically offered through kiosks, such as personnel to check in patients in a waiting area.

Response: The expanded use of kiosks, especially in medical settings, has allowed for recipients to automate portions of their programs and activities, but recipients must take into account the needs of people with disabilities in order to comply with civil rights laws, including section 504. Current Federal laws and regulations require the accessibility of all programs and activities of recipients of Federal financial assistance, including those provided through kiosks.[131] However, the Department believes it is necessary to include a general nondiscrimination provision specific to kiosks in this rulemaking because of how prevalent they have become and because if they

[128] 87 FR 57662 (Sept. 21, 2022).

[129] *See* W3C, *Web Content Accessibility Guidelines 2.1* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* [*https://perma.cc/R6KE-BX3U*].

[130] *Id.*

[131] *See, e.g.,* 45 CFR 92.104; 45 CFR 84.4, redesignated as § 84.68. Note that compliance with these web and mobile accessibility requirements does not remove covered entities' obligations under title I of the ADA to not discriminate against qualified individuals on the basis of disability in regard to job application procedures; the hiring, advancement, or discharge of employees; employee compensation; job training; or other terms, conditions, and privileges of employment. These obligations include making reasonable accommodation to the known physical or mental limitations of applicants or employees, absent undue hardship.

are not designed with people with disabilities in mind they may serve as barriers to recipient programs and activities. Accordingly, the Department is finalizing a provision highlighting the application of general nondiscrimination requirements to recipients that use kiosks in their programs and activities.

While there is support among commenters for the rulemaking to impose measurable accessibility standards for kiosks, similar to those required of web content, mobile applications, and medical diagnostic equipment (MDE) in this rulemaking, the Department does not believe that is feasible at this time. While WCAG 2.1 and the Access Board's MDE Standards were both created after years of research, input, and testing, no comparable standard currently exists for kiosks, except to the extent that kiosks rely on web content or mobile apps as defined in § 84.10. The Access Board submitted an advanced notice of proposed rulemaking that sought public comment on requirements for self-service transaction machines, but that rulemaking has not been finalized.[132]

Recipients that use kiosks must make their programs accessible to persons with disabilities and may do so by instituting procedures that would allow persons with disabilities who cannot use kiosks because of their inaccessible features to access the program without using kiosks.[133] For example, a clinic or a social services office may allow persons with disabilities to go directly to the personnel at the main desk to register for necessary services. Such work-around procedures must afford persons with disabilities the same access, the same convenience, and the same confidentiality that the kiosk system provides.

In instances where kiosks are closed functionality devices that do not rely on web content or mobile apps, the proposed technical standards in § 84.84 will not apply. Under these circumstances, recipients are still obligated to ensure that individuals with disabilities are not excluded from participation in, denied the benefits of, or otherwise subjected to discrimination in any program or activity of the recipient, including the information exchange that would occur at the kiosk. This may require the recipient to provide reasonable modifications to policies, practices, or procedures, as required by § 84.68(b)(7), and take appropriate steps to ensure effective communication, including through the provision of appropriate auxiliary aids and services, which include accessible electronic and information technology, as required by subpart H.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.83 as proposed without modifications.

Requirements for Web and Mobile Accessibility (§ 84.84)

Proposed § 84.84(a) stated that recipients must ensure their web content and mobile applications made available to members of the public or used to offer programs or activities to members of the public must be readily accessible to and usable by individuals with disabilities.

Proposed § 84.84(b) required that recipients ensure their web content and mobile applications made available to members of the public or used to offer programs or activities to members of the public comply with the success criteria and conformance requirements of WCAG 2.1 Level A and Level AA within two or three years of the publication of this rule, depending on whether the recipient has fifteen or more employees, or fewer than fifteen employees, respectively. The section incorporated WCAG 2.1 by reference.

We invited comment on the following questions:

- *Web Accessibility Question 4: Are there technical standards or performance standards other than WCAG 2.1 that the Department should consider? For example, if WCAG 2.2 is finalized before the Department issues a final rule, should the Department consider adopting that standard? If so, what is a reasonable time frame for recipient conformance with WCAG 2.2 and why? Is there any other standard that the Department should consider, especially in light of the rapid pace at which technology changes?*
- *Web Accessibility Question 5: What compliance costs and challenges might small recipients face in conforming with this rule? How accessible are small recipients' current web content and mobile apps? Do small recipients have internal staff to modify their web content and mobile apps, or do they use outside consulting staff to modify and maintain their web content and mobile apps? If small recipients have recently, for example in the past three years, modified their web content and mobile apps to make them accessible, what costs were associated with those changes?*
- *Web Accessibility Question 6: Should the Department adopt a different WCAG version or conformance level for small recipients or a subset of small recipients?*
- *Web Accessibility Question 7: How do recipients use social media platforms and how do members of the public use content made available by recipients on social media platforms? What kinds of barriers do people with disabilities encounter when attempting to access recipients' services via social media platforms?*
- *Web Accessibility Question 8: How do recipients use mobile apps to make information and services available to the public? What kinds of barriers do people with disabilities encounter when attempting to access recipients' programs and activities via mobile apps? Are there any accessibility features unique to mobile apps that the Department should be aware of?*
- *Web Accessibility Question 9: Is WCAG 2.1 Level AA the appropriate accessibility standard for mobile apps? Should the Department instead adopt another accessibility standard or alternatives for mobile apps, such as the requirements from section 508 discussed above?*
- *Web Accessibility Question 10: How will the proposed compliance date affect small recipients? Are there technical or budget constraints that small recipients would face in complying with this rule, such that a longer phase-in period is appropriate?*
- *Web Accessibility Question 11: How will the proposed compliance date affect people with disabilities, particularly in rural areas?*
- *Web Accessibility Question 12: How should the Department define ''small recipient''? Should categories of small recipients other than those already delineated in this proposed rule be subject to a different WCAG 2.1 conformance level or compliance date?*
- *Web Accessibility Question 13: Should the Department consider factors other than the number of employees, such as annual budget, when establishing different or tiered compliance requirements? If so, what should those factors be, why are they more appropriate than the number of employees, and how should they be used to determine regulatory requirements?*
- *Web Accessibility Question 14: Should the Department consider other methods to ensure that a recipient that is also a public entity under title II of the ADA has a single compliance period to come into conformance with WCAG 2.1 AA? If so, what should those methods be?*
- *Web Accessibility Question 15: Should the Department consider a*

[132] 87 FR 57662 (Sept. 21, 2022).

[133] 45 CFR 84.22(b).

different compliance date for the captioning of live-audio content in synchronized media or exclude some recipients from the requirement? If so, when should compliance with this success criterion be required and why? Should there be a different compliance date for different types or sizes of recipients?

• *Web Accessibility Question 16: What types of live-audio content do small recipients post? What has been the cost for providing live-audio captioning?*

The comments and our responses regarding § 84.84 are set forth below.

Comment: Some commenters expressed concern that, as written, the rule would not apply to third party vendors that recipients contract with to create and maintain web content or mobile apps. Commenters noted that many recipients rely on third parties to create or update their web content and mobile apps, and that any rulemaking that does not clearly address those third parties would risk causing confusion and noncompliance.

Response: As the Department made clear in the preamble of the proposed rule, its intent is that websites operated on behalf of a recipient by a third party be covered by the rule. Based on the comments it received, the Department has determined that it should edit §§ 84.84(a)(1) and (2) and (b)(1) and (2) and 84.85(c) to make clear that the general requirements for web content and mobile app accessibility apply when a recipient, ''directly or through contractual, licensing, or other arrangements,'' provides or makes available web content or mobile apps. These edits will dispel any doubt that recipients cannot delegate away their obligations under section 504.

The phrase ''directly or through contractual, licensing, or other arrangements'' comes from existing regulatory language in section 504. The section on general prohibitions against discrimination in the existing section 504 regulation says that ''[a] recipient, in providing any aid, benefit, or service, may not, directly or through contractual, licensing, or other arrangements, on the basis of disability'' engage in various forms of discrimination.[134] The Department intentionally used the same phrasing in this rule to indicate that where recipients act through third parties using contractual, licensing, or other arrangements, they are not relieved of their obligations under this subpart.

Further, the Department notes that the phrase ''provides or makes available'' in § 84.84 is not intended to mean that § 84.84 only applies where the recipient created or owns the web content or mobile app. The plain meaning of ''make available'' includes situations where a recipient relies on a third party to operate or furnish content. Section 84.84 means that recipients provide or make available web content and mobile apps even where recipients do not design or own the web content or mobile app, if there is a contractual, licensing, or other arrangement through which the recipient uses the web content or mobile app to provide a program or activity.

The Department made another minor revision to § 84.84(a)(1) and (2). In the NPRM, § 84.84(a)(1) and (2) applied to web content and mobile apps that a recipient ''makes available to members of the public or uses to offer programs or activities to members of the public.'' [135] In the final rule, the Department revised § 84.84(a)(1) and (2) to apply to web content and mobile apps that a recipient ''provides or makes available.'' The Department also made corresponding revisions to the language of § 84.84(b)(1) and (2). The Department notes that the revised language does not change or limit the coverage of the final rule as compared to the NPRM. Rather, this change ensures consistency between the regulations implementing section 504 and title II of the ADA, respectively, and the broad coverage that both regulatory frameworks provide. The Department's section 504 regulation, at § 84.2, applies to all programs or activities of recipients; the title II regulation, at 28 CFR 35.102, states that the regulation applies to all services, programs, and activities ''provided or made available'' by covered entities. The Department therefore employs the ''provided or made available'' language in the final rule to avoid introducing confusion as to scope of coverage for recipients covered by both frameworks and maintain consistency between section 504 and title II.

Comment: Almost all of the comments on subpart I supported the general concept of requiring that the web content, mobile applications, and kiosks used by recipients be accessible to people with disabilities. Commenters noted the importance of web content, mobile applications, and kiosks in the delivery of health care, including their expanded importance during the COVID–19 Public Health Emergency, and pointed out specific instances where the only way to access a recipient's programs and activities was through web content, mobile applications, and kiosks. Commenters also stated that there are severe consequences when recipients do not provide accessible web content, mobile applications, and kiosks, including barriers to access to necessary health care, poor health outcomes, and even death for people with disabilities. Many commenters noted that some current web content, mobile applications, and kiosks are not designed with accessibility in mind, meaning that people with certain disabilities are unable to use them. Many commenters also expressed their agreement with the concept of a set standard to provide recipients and individuals certainty when determining whether web content, mobile applications, and kiosks are accessible under the law.

Response: The Department appreciates the comments and agrees that ensuring web content, mobile applications, and kiosks that recipients provide or make available are accessible to people with disabilities is necessary to avoid discrimination, health disparities, and poor outcomes. Recipients are increasingly using technology as part of their programs and activities, and unless that technology is accessible, people with disabilities will be left behind. The Department believes that adopting technical standards for web content and mobile app accessibility provides clarity to recipients regarding how to make accessible the programs and activities they offer via the web and mobile apps. Adopting specific technical standards for web content and mobile app accessibility also provides individuals with disabilities with consistent and predictable access to the web content and mobile apps of recipients. Web content, mobile apps, and kiosks already play a large role in the health and human services programs and activities offered by recipients, and that role will likely continue to grow in the future. This rulemaking is necessary given these realities.

Comment: A minority of commenters expressed displeasure with certain aspects of proposed subpart I, including a concern that any new requirements for web content, mobile app, and kiosk accessibility would result in financial burdens that would cause small clinics to shut down. One commenter also expressed opposition to preamble language that stated a phone line operated 24 hours a day, 7 days a week, would not be an acceptable alternative to providing accessible web content, mobile applications, and kiosks.

Response: The Department appreciates the concerns of these

[134] 45 CFR 84.4(b)(1) and (4).

[135] 88 FR 63392, 63509 (Sept. 14, 2023).

commenters and has taken steps to reduce burdens on small recipients. Under § 84.84(b)(2) of the final rule, small recipients, like all other recipients, need to conform to WCAG 2.1 Level AA,[136] but small recipients have three years, instead of the two years provided to larger recipients, to come into compliance. In addition, small recipients (like all recipients) can rely on the five exceptions set forth in § 84.85, in addition to the other mechanisms that are designed to make it feasible for all recipients to comply with the rule, as set forth in §§ 84.86, 84.87, 84.88, and 84.89. Recipients are not required to take action that would constitute a fundamental alteration in the nature of a program or activity or an undue financial or administrative burden. As discussed in the NPRM,[137] and consistent with DOJ's 2022 guidance on web accessibility [138] and DOJ's recent proposed title II rulemaking, ''Nondiscrimination on the Basis of Disability; Accessibility of Web Information and Services of State and Local Government Entities,'' [139] the Department does not believe that a phone line, even if it is staffed 24 hours a day, can realistically provide equal opportunity to people with disabilities. Websites—and often mobile apps—allow members of the public to get information or request a service within just a few minutes, and often to do so independently. Getting the same information or requesting the same service using a staffed phone line takes more steps and may result in wait times or difficulty getting the information. In addition, a staffed telephone line may not be accessible to someone who is deafblind, or who may have combinations of other disabilities, such as a coordination issue impacting typing; and an audio processing disability impacting comprehension over the phone. However, such individuals may be able to use web content and mobile apps that are accessible.

While existing civil rights laws, including the ADA and section 1557, already require that many of the recipients covered by section 504 make their web content, mobile apps, and kiosks accessible to people with disabilities, the Department believes, and the majority of commenters agree, that a regulation with a set standard is the most effective method to ensure that recipients are fulfilling their civil rights obligations.

Comment: Many commenters noted that in October of 2023, W3C issued WCAG 2.2 and requested that the Department use WCAG 2.2 instead of WCAG 2.1 as the accessibility standard for web content and mobile apps in this rulemaking. Those commenters stated that WCAG 2.2 includes new success criteria and builds off of WCAG 2.1, providing additional accessibility for people with disabilities without undermining key provisions from WCAG 2.1. Some commenters stated that the appropriate standards for this rulemaking are those set forth under the regulations for section 508 of the Rehabilitation Act [140] since it applies to all information and communication technology (ICT) rather than just web content. Some commenters also want the Department to impose additional standards for specific file types, such as PDF/UA1 for pdfs. Some commenters requested that the Department establish an evolving standard that automatically upgrades to the most recently released WCAG version, reasoning that both technology and standards to make that technology accessible are constantly changing. One commenter stated that they hope the Department will adopt whatever standard DOJ adopts in its title II web content rulemaking to make compliance with multiple standards easier for recipients that are covered by both rulemakings (89 FR 31320, April 24, 2024). Some commenters requested that there be no standard for compliance and recipients would simply be encouraged to conform to WCAG and make sure that their web content and mobile applications are generally accessible.

Response: The Department appreciates the range of responses received and recognizes that there are various possible technical standards for this rulemaking. The Department has determined that WCAG 2.1 Level AA [141] is the most appropriate standard for this rulemaking. As some commenters noted, WCAG 2.1 Level AA is a widely used and accepted industry standard for accessibility, and requiring conformance to WCAG 2.1 Level AA would result in a significant step forward in ensuring access for people with disabilities. In addition, because WCAG 2.1 Level AA was published in 2018, web developers and recipients have had time to familiarize themselves with it. The WCAG standards were designed to be ''technology neutral.'' [142] This means that they are designed to be broadly applicable to current and future web technologies.[143] Thus, WCAG 2.1 also allows web and mobile app developers flexibility and potential for innovation. WCAG 2.1 Level AA also includes success criteria addressing the accessibility of mobile apps or web content viewed on a mobile device.

WCAG 2.2 was released on October 5, 2023, and adds six additional Level A and AA success criteria beyond those included in WCAG 2.1 while removing

[136] The Web Accessibility Initiative published some revisions to WCAG 2.1 on September 21, 2023. *See* W3C, *Web Content Accessibility Guidelines (WCAG) 2.1* (Sept. 21, 2023), *https://www.w3.org/TR/WCAG21/* [*https://perma.cc/4VF7-NF5F*]. However, this rule requires conformance to the version of WCAG 2.1 that was published in 2018. W3C, *Web Content Accessibility Guidelines 2.1* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F*. The Department believes that recipients have not had sufficient time to become familiar with the 2023 version. Recipients also may not have had an adequate opportunity to comment on whether the Department should adopt the 2023 version, which was published after the NPRM was published. One recent revision to WCAG 2.1 relates to Success Criterion 4.1.1, which addresses parsing. W3C has described Success Criterion 4.1.1 as ''obsolete'' and stated that it ''is no longer needed for accessibility.'' W3C, *WCAG 2 FAQ, https://www.w3.org/WAI/standards-guidelines/wcag/faq/#parsing411* [*https://perma.cc/24FK-V8LS*] (Oct. 5, 2023). According to the 2023 version of WCAG, Success Criterion 4.1.1 ''should be considered as always satisfied for any content using HTML or XML.'' W3C, *Web Content Accessibility Guidelines (WCAG) 2.1* (Sept. 21, 2023), *https://www.w3.org/TR/WCAG21/* [*https://perma.cc/4VF7-NF5F*]. The Department believes that either adopting this note from the 2023 version of WCAG or not requiring conformance to Success Criterion 4.1.1 is likely to create significant confusion. And although Success Criterion 4.1.1 has been removed from WCAG 2.2, W3C, *WCAG 2 FAQ, https://www.w3.org/WAI/standards-guidelines/wcag/faq/#parsing411* [*https://perma.cc/45DS-RRYS*] (Oct. 5, 2023), the Department has decided not to adopt WCAG 2.2 for the reasons described herein. Therefore, conformance to Success Criterion 4.1.1 is still required by this rule. Recipients that do not conform to Success Criterion 4.1.1 would nonetheless be able to rely on § 84.89 to satisfy their obligations under this rule if the failure to conform to Success Criterion 4.1.1 would not affect the ability of individuals with disabilities to use the recipient's web content or mobile app in the manner described in that section. The Department expects that this provision will help recipients avoid any unnecessary burden that might be imposed by Success Criterion 4.1.1.

[137] 88 FR 63392, 63420 (Sept. 14, 2023).

[138] U.S. Dep't of Justice, *Guidance on Web Accessibility and the ADA, ADA.gov* (March 18, 2022), *https://www.ada.gov/resources/web-guidance/* [*https://perma.cc/WH9E-VTCY*] (this guidance did not include 24/7 staffed telephone lines as alternatives to accessible websites).

[139] 88 FR 51948, 51953 (Aug. 4, 2023) (stating that DOJ ''no longer believes 24/7 staffed telephone lines can realistically provide equal access to people with disabilities.'').

[140] 36 CFR part 1194, appendix A.

[141] Conformance to Level AA requires satisfying the success criteria labeled Level A as well as those labeled Level AA, in addition to satisfying the relevant conformance requirements.

[142] W3C, *Introduction to Understanding WCAG* (June 20, 2023), *https://www.w3.org/WAI/WCAG21/Understanding/intro* [*https://perma.cc/XB3Y-QKVU*].

[143] *See* W3C, *Understanding Techniques for WCAG Success Criteria* (June 20, 2023), *https://www.w3.org/WAI/WCAG21/Understanding/understanding-techniques* [*https://perma.cc/AMT4-XAAL*].

the success criteria for parsing.[144] The Department recognizes that WCAG 2.2 is a newer standard, but in crafting this final rule the Department sought to balance benefits for individuals with disabilities with feasibility for recipients making their content accessible in compliance with this rule. The Department believes there will be fewer resources and less guidance available to web professionals and recipients on the new success criteria in WCAG 2.2. Given the benefits of WCAG 2.2 highlighted by commenters, some recipients might choose to implement WCAG 2.2 to provide an even more accessible experience for individuals with disabilities and to increase customer service satisfaction. The Department notes that this rule provides for equivalent facilitation in § 84.87, meaning recipients could choose to comply with this rule by conforming their web content to WCAG 2.2 Level AA because WCAG 2.2 Level AA provides substantially equivalent or greater accessibility and usability to WCAG 2.1 Level AA. This would be sufficient to meet the standard for equivalent facilitation in § 84.87, which is discussed in more detail later.

For several legal reasons, the Department is unable to adopt an evolving standard that continuously updates to the newest version of WCAG. First, the Department is incorporating WCAG 2.1 Level AA by reference into this rule and must abide by the Office of the Federal Register's regulation regarding incorporation by reference.[145] This regulation states that ''[i]ncorporation by reference of a publication is limited to the edition of the publication that is approved [by the Office of the Federal Register]. Future amendments or revisions of the publication are not included.'' [146] Accordingly, the Department only incorporates a particular version of the technical standard and does not state that future versions of WCAG would be automatically incorporated into the rule. In addition, the Department has concerns about regulating to a future standard of WCAG that has yet to be created, of which the Department has no knowledge, and for which compatibility with section 504 and recipients' content is uncertain. The Department believes that adopting WCAG 2.1 as the technical standard for this final rule is more appropriate than adopting WCAG 2.0. WCAG 2.1 provides for important accessibility features that are not included in WCAG 2.0, and an increasing number of governmental entities are using WCAG 2.1. A number of countries that have adopted WCAG 2.0 as their standard are now making efforts to move or have moved to WCAG 2.1.[147] In countries that are part of the European Union, public sector websites and mobile apps generally must meet a technical standard that requires conformance with the WCAG 2.1 success criteria.[148] And WCAG 2.0 is likely to become outdated or less relevant more quickly than WCAG 2.1. As discussed above, WCAG 2.2 was recently published and includes even more success criteria for accessibility.

The Department expects that the wide usage of WCAG 2.0 lays a solid foundation for recipients to become familiar with and implement WCAG 2.1's additional Level A and AA criteria. The Department understands that dozens of States either use or strive to use WCAG 2.0 or greater—either on its own or by way of implementing the section 508 technical standards—for at least some of their web content. It appears that at least ten States—Alaska, Delaware, Georgia, Louisiana, Massachusetts, Oregon, Pennsylvania, South Dakota, Utah, and Washington—already either use WCAG 2.1 or strive to use WCAG 2.1 for at least some of their web content. Given that WCAG 2.1 is a more recent standard than WCAG 2.0, adds some important criteria for accessibility, and has been in existence for long enough for web developers and recipients to get acquainted with it, the Department views it as more appropriate for adoption in this final rule than WCAG 2.0. In addition, even to the extent recipients are not already acquainted with WCAG 2.1, those recipients will have two or three years to come into compliance with a final rule, which should also provide sufficient time to become familiar with and implement WCAG 2.1. The Department also declines to adopt the Access Board's section 508 standards, which are harmonized with WCAG 2.0, for the same reasons it declines to adopt WCAG 2.0.

The Department has coordinated with DOJ and their rulemaking revising the regulation implementing title II of the ADA to establish specific requirements, including the adoption of specific technical standards, for making accessible the services, programs, and activities offered by State and local government entities to the public through the web and mobile apps, to eliminate or minimize instances where recipients that are also public entities under title II will be held to different standards. The goal of the Department is to issue clear and comprehensive rulemaking that requires accessibility for people with disabilities without causing unnecessary confusion among recipients.

The Department declines to adopt additional technical standards related to documents-. As discussed, the WCAG standards were designed to be ''technology neutral'' [149] and are designed to be broadly applicable to current and future web technologies. The Department is concerned that adopting multiple technical standards related to different types of web content and content in mobile apps could lead to confusion. However, the Department notes that this rule allows for equivalent facilitation in § 84.87, meaning that recipients could still choose to comply with additional standards or guidance related to documents to the extent that the standard or technique used provides substantially equivalent or greater accessibility and usability.

Finally, the Department does not intend to simply recommend that recipients make their web content and mobile apps accessible without requiring specific standards and methods of enforcement. As discussed in the NPRM, a variety of voluntary standards and structures have been developed for the web through nonprofit organizations using multinational collaborative efforts. For example, domain names are issued and administered through the internet Corporation for Assigned Names and Numbers, the internet Society publishes computer security policies and procedures for websites, and the World

[144] W3C®, Web Content Accessibility Guidelines 2.2 (Oct. 5, 2023), *https://www.w3.org/TR/WCAG22/.*

[145] *See* 1 CFR 51.1(f).

[146] *Id.*

[147] *See, e.g., Exploring WCAG 2.1 for Australian government services,* Austl. Gov't Digital Transformation Agency (Aug. 22, 2018), *https://www.dta.gov.au/blogs/exploring-wcag-21-australian-government-services.* A Perma archive link was unavailable for this citation; W3C, *Denmark (Danmark)* (updated Mar. 15, 2023), *https://www.w3.org/WAI/policies/denmark/#bekendtg%C3%B8relse-om-afgivelse-af-tilg%C3%A6ngelighedserkl%C3%A6ring-for-offentlige-organers-websteder-og-mobilapplikationer* [*https://perma.cc/K8BM-4QN8*]; *see also* W3C, *Web Accessibility Laws & Policies* (updated Dec. 2023), *https://www.w3.org/WAI/policies/* [*https://perma.cc/6SU3-3VR3*].

[148] *Web Accessibility,* European Comm'n (updated July 13, 2022), *https://digital-strategy.ec.europa.eu/en/policies/web-accessibility* [*https://perma.cc/LSG9-XW7L*]; *Accessibility Requirements for ICT Products and Services,* European Telecomm. Standards Inst., 45–51, 64–78 (Mar. 2021), *https://www.etsi.org/deliver/etsi_en/301500_301599/301549/03.02.01_60/en_301549v030201p.pdf* [*https://perma.cc/5TEZ-9GC6*].

[149] W3C, *Introduction to Understanding WCAG* (June 20, 2023), *https://www.w3.org/WAI/WCAG21/Understanding/intro* [*https://perma.cc/XB3Y–QKVU*].

Wide Web Consortium (''W3C'') develops a variety of technical standards and guidelines ranging from issues related to mobile devices and privacy to internationalization of technology. In the area of accessibility, the Web Accessibility Initiative (''WAI'') of the W3C created the WCAG.

Many organizations, however, have indicated that voluntary compliance with these accessibility guidelines has not resulted in equal access for people with disabilities; accordingly, they have urged the Department to take regulatory action to ensure web content and mobile app accessibility.[150] The National Council on Disability, an independent Federal agency that advises the President, Congress, and other agencies about programs, policies, practices, and procedures affecting people with disabilities, has similarly emphasized the need for regulatory action on this issue.[151]

Recent research documents the digital inaccessibility of the websites of more than 100 top hospitals across the United States, finding that only 4.9 percent are fully compliant with Web Content Accessibility Guidelines (WCAG) 2.1.[152] While WCAG 2.1 has been available to the general public, including web professionals, for over five years, and many of the success criteria it incorporates were available a decade prior in WCAG 2.0, it is likely that some recipients have not fully conformed with WCAG 2.1 AA in the absence of rulemaking requiring conformance. In general, as technology continues to advance, the methods for ensuring programs and activities are as effective for people with disabilities as those provided to others may need to change, as well.[153]

Despite the availability of voluntary web and mobile app accessibility standards; the Department's position that programs and activities of recipients, including those available on websites, must be accessible; and case law supporting that position, individuals with disabilities continue to struggle to obtain access to the websites of recipients.[154] In addition to the Department's guidance and enforcement, DOJ has brought enforcement actions to address web access, resulting in a significant number of settlement agreements with state and local government entities as well as public entities.[155]

The Department believes that adopting technical standards for web content and mobile app accessibility provides clarity to recipients regarding how to make the programs and activities they offer the public via the web and mobile apps accessible. Adopting specific technical standards for web content and mobile app accessibility also provides individuals with disabilities with consistent and predictable access to the websites and mobile apps of recipients.

Comment: Many commenters expressed their beliefs that the proposed time periods for compliance, two years for larger recipients and three years for smaller recipients, were too far in the future and should be shortened. These commenters expressed concern that the time recipients would spend making their web and mobile content accessible would be time that people with disabilities will not have access to their programs and activities, including necessary health care. Alternatively, some commenters stated they believed that the time periods for compliance should be extended to allow recipients, some of whom are small and have limited resources, additional time to come into compliance and ensure their web content and mobile apps comply with WCAG 2.1. These commenters stated that some small health care providers may decide to not accept funding from the Department, or go out of business altogether, if they are

[150] *See, e.g.,* Letter from Am. Ass'n of People with Disabilities et al. to the Department (Feb. 24, 2022), *https://www.aapd.com/wp-content/uploads/2022/03/HHS_Disability-Advocates-Memo-02.24.22.pdf* (noting that increased use of telehealth has led to some accessibility challenges for individuals with disabilities and requesting that the Department provide clear guidance on telehealth accessibility requirements); Letter from American Council of the Blind et al. to U.S. Dep't of Justice. (Feb. 28, 2022), *https://acb.org/accessibility-standards-joint-letter-2-28-22* [*https://perma.cc/R77M-VPH9*] (citing research showing persistent barriers in digital accessibility); Letter from Consortium for Citizens with Disabilities to U.S. Dep't of Justice. (Mar. 23, 2022), *https://www.c-c-d.org/fichiers/CCD-Web-Accessibility-Letter-to-DOJ-03232022.pdf* [*https://perma.cc/Q7YB-UNKV*].

[151] National Council on Disability, *The Need for Federal Legislation and Regulation Prohibiting Telecommunications and Information Services Discrimination* (Dec. 19, 2006), *https://www.ncd.gov/publications/2006/Dec282006* [*https://perma.cc/7HW5-NF7P*] (discussing how competitive market forces have not proven sufficient to provide individuals with disabilities access to telecommunications and information services); *see also, e.g.,* National Council on Disability, *National Disability Policy: A Progress Report* (Oct. 7, 2016), *https://ncd.gov/progress report/2016/progress-report-october-2016* [*https://perma.cc/J82G-6UU8*] (urging the Department to adopt a web accessibility regulation).

[152] Amanda Krupa et al., American Health Information Management Association (AHIMA) Foundation, The Critical Role of Web Accessibility in Health Information Access, Understanding, and Use (2022), *https://mathematica.org/publications/the-critical-role-of-web-accessibility-in-health-information-access-understanding-and-use.*

[153] *See, e.g., Enyart* v. *Nat'l Conference,* 630 F. 3d 1153, 1163 (9th Cir. 2011) (an ADA title II case, in which the defendant refused to permit the plaintiff to take the Bar exam using a computer equipped with the assistive technology software JAWS and ZoomText. The court held that the software must be permitted, stating that ''assistive technology is not frozen in time: as technology advances, testing accommodations should as well.''); *See also California Council of the Blind* v. *Cnty of Alameda,* 985 F. Supp. 2d 1229, 1241 (N.D. Cal. 2013) (the plaintiffs alleged a violation of section 504 and the ADA because of defendant's failure to provide electronic voting machines with electronic ballots including an audio ballot feature that can read aloud instructions and voting options. In denying the defendant's motion to dismiss, the court noted that ''while the Social Security Administration's practice of reading notices to blind individual was once sufficient, reading letters over the phone no longer constituted meaningful access because 'great strides have been made in computer-aided assistance for the blind . . .' ''); *Argenyi* v. *Creighton Univ.,* 703 F. 3d 441 (8th Cir. 2013) (the court held that the University's failure to provide a system which transcribes spoken words into text on a computer screen violated section 504 and the ADA.).

[154] *See, e.g., Meyer* v. *Walthall,* 528 F. Supp. 3d 928, 959 (S.D. Ind. 2021) (''[T]he Court finds that Defendants' websites constitute services or activities within the purview of Title II and section 504, requiring Defendants to provide effective access to qualified individuals with a disability.''); *Price* v. *City of Ocala, Fla.,* 375 F. Supp. 3d 1264, 1271 (M.D. Fla. 2019) (''Title II undoubtedly applies to websites . . . .''); *Payan* v. *Los Angeles Cmty. Coll. Dist.,* No. 2:17–CV–01697–SVW–SK, 2019 WL 9047062, at *12 (C.D. Cal. Apr. 23, 2019) (''[T]he ability to sign up for classes on the website and to view important enrollment information is itself a 'service' warranting protection under Title II and section 504.''); *Eason* v. *New York State Bd. of Elections,* No. 16–CV–4292 (KBF), 2017 WL 6514837 (S.D.N.Y. Dec. 20, 2017) (stating, in a case involving a State's website, that ''section 504 of the Rehabilitation Act and Title II of the Americans with Disabilities Act . . . ,long ago provided that the disabled are entitled to meaningful access to a recipient's programs and services. Just as buildings have architecture that can prevent meaningful access, so too can software.''); *Hindel* v. *Husted,* No. 2:15–CV–3061, 2017 WL 432839, at *5 (S.D. Ohio Feb. 1, 2017) (''The Court finds that Plaintiffs have sufficiently established that Secretary Husted's website violates Title II of the ADA because it is not formatted in a way that is accessible to all individuals, especially blind individuals like the Individual Plaintiffs whose screen access software cannot be used on the website.'').

[155] *See, e.g.,* Settlement Agreement Between the United States of America and the Champaign-Urbana Mass Transit District (Dec. 14, 2021), *https://www.ada.gov/champaign-urbana_sa.pdf* [*https://perma.cc/VZU2-E6FZ*]; Consent Decree, *United States* v. *The Regents of the Univ. of Cal.* (Nov. 20, 2022), *https://www.justice.gov/opa/press-release/file/1553291/download* [*https://perma.cc/9AMQ-GPP3*]; Consent Decree, *Dudley* v. *Miami Univ.* (Oct. 13, 2016), *https://www.ada.gov/miami_university_cd.html* [*https://perma.cc/T3FX-G7RZ*]; Settlement Agreement Between the United States of America and the City and County of Denver, Colorado Under the Americans with Disabilities Act (Jan. 8, 2018), *https://www.ada.gov/denver_pca/denver_sa.html* [*https://perma.cc/U7VE-MBSG*]; Settlement Agreement Between the United States of America and Nueces County, Texas Under the Americans with Disabilities Act (effective Jan. 30, 2015), *https://www.ada.gov/nueces_co_tx_pca/nueces_co_tx_sa.html* [*https://perma.cc/TX66-WQY7*]; Settlement Agreement Between the United States of America, Louisiana Tech University, and the Board of Supervisors for the University of Louisiana System Under the Americans with Disabilities Act (July 22, 2013), *https://www.ada.gov/louisiana-tech.htm* [*https://perma.cc/78ES-4FQR*].

required to come into compliance within three years. Some commenters believe that the proposed time period for compliance is adequate and strikes the appropriate balance between providing recipients adequate time and ensuring people with disabilities do not have to wait too long for services.

Some commenters expressed confusion as to whether the proposed rule as drafted only meant that recipients had a one-time obligation to update their web content and mobile apps for WCAG 2.1 AA conformance at two years or three years, depending on their size.

Response: Much like determining the appropriate compliance standard, the Department recognizes that commenters have a spectrum of opinions on whether the proposed dates for compliance are too soon or too far in the future. The Department worked closely with its Federal partners to determine appropriate compliance timeframes. After carefully weighing the arguments that the compliance dates should be kept the same, shortened, or lengthened, the Department has decided that the compliance dates in the final rule—two years for large recipients and three years for small recipients—strike the appropriate balance between the various interests at stake.

Shortening the compliance dates would likely result in increased costs and practical difficulties for recipients, especially small recipients. Lengthening the compliance dates would prolong the exclusion of many people with disabilities from recipients' web content and mobile apps. Additionally, any change in compliance dates runs the risk of introducing inconsistency with other rulemakings [156] where recipients that are also covered by those rulemakings would be subject to different compliance dates. The Department believes that the balance struck in the compliance timeframe proposed in the NPRM was appropriate, and that there are no overriding reasons to shorten or lengthen these dates given the important and competing considerations involved by stakeholders.

Regarding whether the proposed rule only required recipients to make their web content and mobile apps accessible once, the Department wishes to clarify that under this rule, recipients have an ongoing obligation to ensure that their web content and mobile apps comply with this rule's requirements, which would include content that is newly added or created after the compliance date. The compliance date is the first time that recipients need to be in compliance with the rule's requirements; it is not the last. Accordingly, after the compliance date, recipients will continue to need to ensure that all web content and mobile apps they provide or make available comply with the technical standard, except to the extent another provision of this rule permits otherwise. To make this point more clearly, the Department revised the language of § 84.84(b)(1) and (2), respectively, to state that a recipient needs to comply with this rule ''[b]eginning May 11, 2026'' and ''[b]eginning May 10, 2027,'' depending on the size of the recipient.

Comment: The Department received conflicting comments concerning the costs and challenges that small recipients will face in order to comply with the proposed rule. Some commenters believe that recipients with fewer than fifteen employees have budgets that will be significantly constrained by requirements to make the web content and mobile apps they use compliant with WCAG 2.1 in any amount of time. Some commenters also believe that because of their size, small recipients are less sophisticated and less aware of their obligations under Federal civil rights laws, and therefore should not be held to standards imposed on larger recipients. Alternatively, other commenters state that small recipients do not face insurmountable costs because advances in technology and the services offered to make web content accessible have made compliance much more attainable for even the smallest recipient.

Response: The Department believes that the final rule strikes the appropriate balance by requiring small recipients to comply with the same technical standard as larger recipients while giving small recipients additional time to do so. The Department believes this longer compliance time frame is prudent in recognition of the additional challenges that small recipients may face in complying, such as limited budgets, lack of technical expertise, and lack of personnel. The Department believes that providing an extra year for small recipients to conform to this section will give those recipients sufficient time to properly allocate their personnel and financial resources to make their web content and mobile apps comply with WCAG 2.1 Level AA, without providing so much additional time that people with disabilities have a reduced level of access to their resources for an extended period.

The Department appreciates the concerns of commenters and urges recipients to review the Regulatory Impact Analysis for the Department's full discussion of the costs and benefits of the proposed rulemaking. Small recipients in particular are much less likely to create their own web content and mobile apps and are more likely to contract with outside parties. Small recipients are also more likely to have smaller amounts of web content and mobile apps that would have to be compliant. Recipients will have the choice to remediate existing web content and mobile apps, or to create new accessible web content and mobile apps and may also decide whether to make changes themselves or contract with a third-party to make changes. Regarding sophistication and understanding of accessibility requirements, the Department is committed to issuing guidance and technical assistance for recipients on how to comply with accessibility requirements, in addition to existing guidance on WCAG 2.1. Finally, a recipient may be able to show that full compliance with subpart I would result in a fundamental alteration or undue burdens as described in § 84.88.

Comment: Many commenters believe that all recipients, regardless of size, should be held to the same accessibility standard. Specifically, they believe that any deviation in accessibility standards between small and large recipients would lead to unacceptable differences in levels of care to the detriment of patients with disabilities, especially those in rural areas. Those commenters also stated that small recipients should either have to come into compliance within the proposed three years or at an earlier date. Some commenters supported more lenient standards for small recipients because they believed achieving full accessibility under WCAG 2.1 would be too difficult for the smallest recipients. One commenter stated that the accessibility standard should be the same regardless of recipient size, but small providers should have more than three years to come into compliance. One commenter recommended a principles-based approach where small recipients would be required to take steps to make their web content and mobile apps accessible, but there would be no standard or method for testing their accessibility. One commenter believed there should be a permanent exemption for small recipients and that they should not be held to any standards for web content and mobile app accessibility. Finally, some commenters requested additional guidance for small recipients so that they could comply with the Department's proposed standards.

[156] *See, e.g.,* 88 FR 51948 (Aug. 4, 2023).

Response: The Department appreciates the range of responses on standards for small recipients. The Department agrees that requiring more lenient standards for small recipients would lead to differences in the accessibility and effectiveness of health and human service programs and activities. Given the importance of small recipients in the delivery of health care, such gaps are incompatible with the Department's statutory mandate; a wholesale exception would therefore be inappropriate. Such an exception would mean that an individual with a disability who lives in a small, rural area, might not have the same level of access to a recipient's web-based programs and activities as an individual with a disability in a larger, urban area. This would significantly undermine consistency and predictability in web accessibility. It would also be particularly problematic given the interconnected nature of many different websites. Furthermore, an exception for small recipients would reduce the benefits of the rule for those entities.

Requiring small recipients to comply with the same technical standards as all other recipients ensures consistent levels of accessibility for recipients of all sizes in the long term, which will promote predictability and reduce confusion about which standard applies. It will allow for individuals with disabilities to know what they can expect when navigating a recipient's web content; for example, it will be helpful for individuals with disabilities to know that they can expect to be able to navigate any recipient's web content independently using their assistive technology. It also ensures that individuals with disabilities who reside in rural areas that are mainly serviced by smaller recipients have comparable access to their counterparts in urban areas that are serviced by a range of smaller and larger recipients, which is critical given the transportation and other barriers that people in rural areas may face.[157]

The Department notes that under appropriate circumstances, small recipients may also rely on the exceptions, flexibilities, and other mechanisms described in §§ 84.85, 84.86, 84.87, 84.88, and 84.89 below, which the Department believes should help make compliance feasible for those recipients. Recipients are not required to take action that would constitute a fundamental alteration in the nature of a program or activity, or impose an undue financial or administrative burden.

Finally, the Department remains committed to making guidance documents and technical assistance available to the general public so that recipients are aware of their obligations and how to comply with them.

New Social Media Exception

Comment: Many of the comments on recipient use of social media and how it should be addressed in this rulemaking stated that recipients use social media for a wide variety of purposes, including purposes central to the programs and activities they provide. Recipients may post important announcements, scheduling information, informational videos, or other general information that is of high importance to the public. Many comments proposed specific technical requirements to ensure that social media posts from recipients are accessible, including plain language, alternative text for images, and audio descriptions and captions for videos. Some commenters stated that social media posts made before the implementation date for this rulemaking should not be required to be accessible unless they contain important information related to recipient programs or activities or the content of the posts is changed. Some commenters stated that older social media posts should be made accessible upon request or if a recipient posts significant important content on a certain social media platform, like YouTube. Some commenters stated that no preexisting social media posts should be required to be accessible due to the burden on recipients and the forward-looking nature of the proposed rule. Many commenters expressed concern that social media posts from recipients should not be deemed to violate this proposed rule if the social media platform itself is responsible for the violation.

Response: The Department is including an exception for preexisting social media posts in the final rule because making preexisting social media posts accessible may be impossible or result in a significant burden. The benefits of making all preexisting social media posts accessible will likely be limited as these posts are generally intended to provide then-current updates on platforms that are frequently refreshed with new information. The Department believes recipients' limited resources are better spent ensuring that current web content and content in mobile apps are accessible, rather than reviewing all preexisting social media posts for compliance or possibly deleting recipients' previous posts if remediation is impossible. As other commenters recommended, the Department believes this final rule should be more forward looking when determining which social media posts should be accessible.

The Department emphasizes that even if preexisting social media posts do not have to conform to the technical standard, recipients still need to ensure that their programs and activities offered using web content and mobile apps are accessible to people with disabilities on a case-by-case basis in accordance with their other obligations under section 504.

Based on these comments, the Department will include a new exception at § 84.85(e) that will state the requirements of § 84.84 do not apply to a recipient's social media posts that were posted before the date the recipient is required to comply with this rule.

The Department's final rule requires that web content and mobile apps that recipients provide or make available, directly or through contractual, licensing, or other arrangements, be made accessible within the meaning of § 84.84. This requirement applies regardless of whether that content is located on the recipient's own website or mobile app or elsewhere on the web or mobile apps. It therefore covers web content or content in a mobile app that a recipient makes available via a social media platform.

Many social media platforms that are widely used by members of the public are available to members of the public separate and apart from any arrangements with recipients to provide a program or activity. As a result, this rule does not require recipients to ensure that such platforms themselves conform to WCAG 2.1 Level AA. However, because the posts that recipients disseminate through those platforms are provided or made

[157] *See, e.g.,* NORC Walsh Ctr. for Rural Health Analysis & Rural Health Info. Hub, *Access to Care for Rural People with Disabilities Toolkit,* (Dec. 2016), *https://www.ruralhealthinfo.org/toolkits/disabilities.pdf* [*https://perma.cc/YX4E-QWEE*] (noting geographic, transportation, and service barriers to care in rural areas); U.S. Dep't of Health & Hum. Servs., Health Rsch. & Servs. Admin., Strengthening the Rural Health Workforce to Improve Health Outcomes in Rural Communities, 13–14 (Apr. 2022), *https://www.hrsa.gov/sites/default/files/hrsa/advisory-committees/graduate-medical-edu/reports/cogme-april-2022-report.pdf* (stating that the healthcare workforce in rural communities is overall short staffed with fewer hospitals and critical care physicians than urban areas); *About Rural Healthcare,* NHRA, *https://www.ruralhealth.us/about-nrha/about-rural-healthcare* (last visited Mar. 19, 2024) (stating that family physicians comprise only 15% of U.S. outpatient physician workforce but provide 42% of care in rural areas).

available by the recipients, they must conform to WCAG 2.1 Level AA. The Department understands that social media platforms often make available certain accessibility features like the ability to add captions or alt text. It is the recipient's responsibility to use these features when it makes web content available on social media platforms. For example, if a recipient posts an image to a social media platform that allows users to post alt text, the recipient needs to ensure that appropriate alt text accompanies that image so that screen reader users can access the information.

Comment: Many of the comments on recipients' use of mobile applications and how it should be addressed in this rulemaking stated that recipients use mobile apps for a wide range of services that are central to their programs and activities. For example, some recipients use mobile apps as the main method for making appointments, paying bills, and even communicating with the recipient. None of the commenters argued against addressing mobile applications in this rulemaking. Some commenters stated that WCAG 2.1 applies to mobile apps in addition to web content and the Department is correct in proposing to use the same standard for both. Some commenters recommended a different standard for mobile apps, like section 508 of the Rehabilitation Act, WCAG 2.2, or WCAG 2.0.

Response: The Department agrees that the same technical standard for accessibility should apply to both web content and mobile apps. The Department believes that applying the same technical standard to both web content and mobile apps will reduce confusion by ensuring consistent requirements and user experiences across web and mobile platforms.

One of the reasons the Department proposed WCAG 2.1 AA as the standard for web content and mobile apps is that the WCAG standards were designed to be ''technology neutral.'' [158] This means that they are designed to be broadly applicable to current and future web technologies,[159] which will help ensure accessibility for mobile apps. Although the Section 508 Standards include some additional requirements like interoperability that are not required by WCAG,[160] WCAG 2.1 Level AA includes specific success criteria related to mobile app accessibility. These success criteria address challenges such as touch target size, orientation, and motion actuation, among others.[161] Therefore, the Department believes that WCAG 2.1 Level AA is a robust framework for mobile app accessibility.

Comment: Most of the comments on how the proposed compliance dates will affect individuals with disabilities noted that the longer that individuals with disabilities are forced to wait for accessible web content and mobile apps, the worse health outcomes they will face. Some commenters noted that retrofitting existing web content is always more difficult than creating accessible content, so recipients should begin making new web content accessible as soon as possible.

Response: The Department agrees that creating accessible content from the start, rather than trying to remediate after the fact, is generally an easier undertaking for recipients and results in lower costs and burdens over time. While recipients must begin complying with the rule on the applicable compliance date, the Department expects that recipients will need to prepare for compliance during the two or three years before the compliance date. In addition, recipients still have an obligation to meet all of section 504's existing requirements—both before and after the date they must initially come into compliance with this rule.

Comment: There were limited comments concerning how to define small recipients under the proposed rulemaking. Some commenters agreed that fifteen was the appropriate employee cut off for small recipients. Some commenters stated that there should be no distinction between small and large recipients because patients require the same level of care regardless of the size of a provider. Some commenters requested that instead of using the section 504 definition of small recipient that includes recipients with fewer than fifteen employees, the Department use the definition from the 2015 Medicare Access and CHIP Reauthorization Act which includes practices with fifteen or fewer professionals, effectively making more recipients small recipients, as the commenters characterized the requested change.

Response: Since its publication over four decades ago, the Department's implementing regulation for section 504 of the Rehabilitation Act has recognized that there are practical differences between recipients with fewer than fifteen employees and recipients with fifteen or more employees. As a result, the Department limited the obligations of recipients with fewer than fifteen employees in certain areas. Maintaining this definition will significantly reduce the administrative complexity of enforcing this regulation and will improve predictability for recipients. The Department will not alter the definition of small recipient under a civil rights regulation to more closely align with a public law focused on physician payments.

Comment: Commenters agreed with the Department's proposed method for compliance for recipients that are also public entities covered by title II of the ADA.

Response: The Department agrees that its proposed method is appropriate. In instances where a recipient is also a public entity covered by title II of the ADA, the recipient will be required to comply with both this rulemaking and all title II regulations, including DOJ's rule establishing specific requirements, including the adoption of specific technical standards, for making accessible the services, programs, or activities offered by State and local government entities to the public through the web and mobile apps, and the associated compliance dates specified in that rulemaking.

Comment: Most commenters agreed that there should not be a separate standard or greater time period for captioning live audio. Many commenters agree that two or three years is adequate time to ensure captioning for live audio, especially given the current advances in automated captioning technology. One commenter asked whether captioning requirements would require captions in multiple different languages beyond English.

Response: As proposed in the NPRM, the final rule applies the same compliance date to all of the WCAG 2.1 Level AA success criteria, including live-audio captioning requirements. As stated in § 84.84(b), this provides three years after publication of the final rule for small recipients to comply, and two years for large recipients. The final rule takes this approach for several reasons. First, the Department understands that live-audio captioning technology has developed in recent years and continues to develop. Additionally, the COVID–19 pandemic moved a significant number of formerly in-person meetings,

[158] W3C, *Introduction to Understanding WCAG* (June 20, 2023), *https://www.w3.org/WAI/WCAG21/Understanding/intro* [*https://perma.cc/XB3Y-QKVU*].

[159] *See* W3C, *Understanding Techniques for WCAG Success Criteria* (June 20, 2023), *https://www.w3.org/WAI/WCAG21/Understanding/understanding-techniques* [*https://perma.cc/AMT4-XAAL*].

[160] *See* 36 CFR 1194.1; 36 CFR part 1194, appendix C, ch. 5.

[161] W3C, *Web Content Accessibility Guidelines (WCAG) 2.1* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F* (success criteria 2.5.5, 1.3.4, & 2.5.4).

activities, and other gatherings to online settings, many of which incorporated live-audio captioning. As a result of these developments, live-audio captioning has become even more critical for individuals with certain types of disabilities. Further, the Department believes that requiring conformance with all success criteria by the same date (according to recipient size) will address the need for both clarity for recipients and predictability for individuals with disabilities.

This rulemaking is separate from other civil rights laws and regulations that prohibit discrimination based on race, color, or national origin and require meaningful access for individuals with limited English proficiency. Additional information on section 1557, which requires that certain health programs and activities take reasonable steps to provide meaningful access to individuals with limited English proficiency, can be found on the OCR website.

Comment: Some commenters noted that recipients post a variety of live audio content, including news blasts.

Response: The Department appreciates the responses.

Summary of Regulatory Changes

While the Department believes that the comments concerning § 84.84 were overall positive and recognized the intent of the proposed rule, there is also concern that more clarity can be provided to define the scope of coverage. Accordingly, the Department will modify the text of § 84.84(a)(1) and (2) and (b)(1) and (2) to clarify that this rulemaking applies to web content and mobile apps that a recipient provides, either ''directly or through contractual, licensing, or other arrangements.'' This approach is consistent with the NPRM, which clarified that throughout this rule, a recipient's 'website' is intended to include not only the websites hosted by the recipient, but also websites operated on behalf of a recipient by a third party. The Department also received comments in other sections emphasizing the importance of such a distinction and believes it is a fundamental part of this rule that should be emphasized.

The Department will also modify the regulatory text of § 84.84 to remove the words ''members of the public,'' which is more similar to the language in the application section of title II of the ADA but is not intended to change or limit the coverage of the final section 504 rule.

The Department will also edit the language at § 84.84(b)(1) and (2) to clarify that recipients have an ongoing obligation, not a one-time obligation, to make their web content and mobile apps accessible beginning two or three years after the publication of this final rule.

Exceptions (§ 84.85)

Proposed § 84.85 contained a number of exceptions to the requirements of § 84.84 including archived web content (§ 84.85(a)), preexisting conventional electronic documents (§ 84.85(b)), web content posted by a third party (§ 84.85(c)), linked third-party web content (§ 84.85(d)), password-protected course content for elementary, secondary, and postsecondary institutions (§ 84.85(e), (f)), and individualized password-protected documents (§ 84.85(g)).

The Department emphasizes that, even if certain content does not have to conform to the technical standard of this rulemaking, recipients still need to ensure that their programs and activities offered using web content and mobile apps are accessible to people with disabilities on a case-by-case basis in accordance with other obligations under this rulemaking. These obligations include making reasonable modifications to avoid discrimination on the basis of disability, ensuring that communications with people with disabilities are as effective as communications with people without disabilities, and providing people with disabilities an equal opportunity to participate in or benefit from the recipient's programs or activities.[162]

The Department sought comment on the following questions pertaining to archived web content (§ 85.85(a)):

- *Web Accessibility Question 17: How do recipients manage content that is maintained for reference, research, or recordkeeping?*
- *Web Accessibility Question 18: What would the impact of this exception be on people with disabilities?*
- *Web Accessibility Question 19: Are there alternatives to this exception that the Department should consider, or additional limitations that should be placed on this exception? How would foreseeable advances in technology affect the need for this exception?*

The comments and our responses on § 84.85(a) are set forth below.

Comment: One commenter stated that its content is stored in accordance with State administrative rules and made available to the public based on open records laws. Several commenters sought clarity on the definition of ''archived web content.'' Some commenters provided their understanding of what constitutes archived web content, and offered suggestions for updating the Department's proposed definition. One comment stated that archiving content includes taking stock of all the material on a website, then the website may be overhauled in such a way that archived relationships or content types are no longer visible. Some commenters requested an edit to the proposed definition of ''archived content'' to remove the term ''exclusively'' as it limits archived web content to content maintained for reference, research or recordkeeping and the commenters did not want to limit the exception to specific types of content.

Response: The Department appreciates the comments about the archived web content definition and exception. Specifically, some commenters offered recommendations to broaden the definition of archived web content, which would increase the total web content covered by the proposed exception, while other comments recommended limiting the definition of archived web content, which would decrease the total web content covered by the proposed exception. In the proposed rule, ''archived web content'' was defined as ''web content that (1) is retained exclusively for reference, research, or recordkeeping; (2) is not altered or updated after the date of archiving; and (3) is organized and stored in a dedicated area or areas clearly identified as being archived.'' [163]

The Department made several revisions to the definition of archived web content from the NPRM. To clarify the scope of content covered by the definition and associated exception, the Department added a new first part to the definition. That new part specifies that archived web content is limited to three types of historic content: web content that was created before the date the recipient is required to comply with subpart I; web content that reproduces paper documents created before the date the recipient is required to comply with subpart I; and web content that reproduces the contents of other physical media created before the date the recipient is required to comply with subpart I.

Web content that was created before the date a recipient is required to comply with subpart I satisfies the first part of the definition. In determining the date web content was created, the Department does not intend to prohibit recipients from making minor adjustments to web content that was initially created before the relevant

[162] *See* 45 CFR 84.68(b)(1)(ii), (b)(7), 84.77.

[163] 88 FR 63392, 63509 (Sept. 14, 2023).

compliance dates specified in § 84.84(b), such as by redacting personally identifying information from web content as necessary before it is posted to an archive, even if the adjustments are made after the compliance date. In contrast, if a recipient makes substantial changes to web content after the date the recipient is required to comply with the rule, such as by adding, updating, or rearranging content before it is posted to an archive, the content would likely no longer meet the first part of the definition. If the recipient later alters or updates the content after it is posted in an archive, the content would not meet the third part of the definition of archived web content and it would generally need to conform to WCAG 2.1 Level AA.

Web content that reproduces paper documents or that reproduces the contents of other physical media would also satisfy the first part of the definition if the paper documents or the contents of the other physical media were created before the date the recipient is required to comply with this rule. Paper documents include various records that may have been printed, typed, handwritten, drawn, painted, or otherwise marked on paper. Videotapes, audiotapes, film negatives, CD–ROMs, and DVDs are examples of physical media. The Department anticipates that recipients may identify or discover historic paper documents or historic content contained on physical media that they wish to post in an online archive following the time they are required to comply with this rule. For example, a research hospital might move to a new building after the date it is required to comply with this rule and discover a box in storage that contains hundreds of paper files and photo negatives from 1975 related to a research study the hospital conducted at that time. If the hospital reproduced the documents and photos from the film negatives as web content, such as by scanning the documents and film negatives and saving the scans as PDF documents that are made available online, the resulting PDF documents would meet the first part of the definition of archived web content because the underlying paper documents and photos were created in 1975. The Department reiterates that it does not intend to prohibit recipients from making minor adjustments to web content before posting it to an archive, such as by redacting personally identifying information from paper documents. Therefore, the hospital could likely redact personally identifying information about participants in the research study from the scanned PDFs as necessary before posting them to its online archive. But, if the hospital were to make substantial edits to PDFs, such as by adding, updating, or rearranging content before posting the PDFs to its archive, the PDFs would likely not meet the first part of the definition of archived web content because, depending on the circumstances, they may no longer be a reproduction of the historic content. In addition, if the hospital later altered or updated the PDFs after they were posted in an archive, the content would not meet the third part of the definition of archived web content and it would generally need to conform to WCAG 2.1 Level AA.

The Department believes the first part of the definition sets an appropriate time-based limitation on the scope of content covered by the definition and exception that is consistent with the Department's stated intent in the NPRM. In the NPRM, the Department explained that the definition of archived web content and the associated exception were intended to cover historic content that is outdated or superfluous.[164] The definition in the final rule, which is based on whether the relevant content was created before the date a recipient is required to comply with subpart I, is now more aligned with, and better situated to implement, the Department's intent to cover historic content. The Department believes it is appropriate to include a time-based limitation in the definition, rather than add new criteria stating that content must be historic, outdated, or superfluous, because it is more straight forward to differentiate content based on the date the content was created. Therefore, there will be greater predictability for individuals with disabilities and recipients as to which content is covered by the exception.

The Department declines to establish time-based limitations for when content may be posted to an archive or to otherwise set an expiration date for the exception. As discussed below, the Department recognizes that many recipients will need to carefully consider the design and structure of their web content before dedicating a certain area or areas for archived content, and that, thereafter, it will take time for recipients to identify all content that meets the definition of archived web content and post it in the newly created archived area or areas. The archived web content exception thus provides recipients flexibility as to when they will archive web content so long as the web content was created before the date the recipient was required to comply with subpart I or the web content reproduces such paper documents or the contents of other physical media created before the date the recipient was required to comply with subpart I. In addition, the Department does not believe it is necessary to establish a waiting period before newly created web content can be posted in an archive. New content created after the date a recipient is required to comply with this rule will generally not meet the first part of the definition of ''archived web content.'' In the limited circumstances in which newly created web content could meet the first part of the definition because it reproduces paper documents or the contents of other physical media created before the date the recipient is required to comply with this rule, the Department believes the scope of content covered by the exception is sufficiently limited by the second part of the definition: whether the content is retained exclusively for reference, research, or recordkeeping.

After considering all the comments, the Department declines to change what is now the second part of the definition of archived web content. Given the wide variety of web content that recipients provide or make available, the Department does not believe it is advisable to try to use additional, more specific language in the definition about what types of content are covered. Whether web content is retained exclusively for reference, research, or recordkeeping will depend on the facts of the particular situation. The Department notes that if a recipient posts web content that identifies the current policies or procedures of the recipient, or posts web content containing or interpreting applicable laws or regulations related to the recipient, that web content is unlikely to be covered by the exception. This is because the content is notifying members of the public about their ongoing rights and responsibilities. It therefore is not, as the definition requires, being used exclusively for reference, research, or recordkeeping.

Also, the Department's revised definition of archived web content, and specifically the new first part of the definition, make clear that the definition only pertains to certain content created before the date the recipient is required to comply with this rule. Therefore, new content such as agendas, meeting minutes, and other documents related to meetings that take place after the recipient is required to comply with this

[164] 88 FR 63392, 63464 (Sept. 14, 2023).

rule would likely not meet all parts of the definition of archived web content.

In addition to adding a new first part to the definition of archived web content, the Department made one further change to the definition from the NPRM. In the NPRM, what is now the second part of the definition pertained to web content that is ''maintained'' exclusively for reference, research, or recordkeeping. In the final rule, the word ''maintained'' is replaced with ''retained.'' The revised language is not intended to change or limit the coverage of the definition. Rather, the Department recognizes that the word ''maintain'' can have multiple meanings relevant to this rule. In some circumstances, ''maintain'' may mean ''to continue in possession'' of property, whereas in other circumstances it might mean ''to engage in general repair and upkeep'' of property.[165]

Additionally, the Department will retain the word ''exclusively'' in the definition of archived web content. The Department is concerned that removing the word ''exclusively'' would result in less predictability for both recipients and individuals with disabilities about the scope of content covered by the definition. In addition, if the Department were to remove the word ''exclusively,'' the exception for archived web content might cover important older web content that is still used for reasons other than reference, research, or recordkeeping. The purpose of the exception for archived web content is to help recipients focus their resources on making accessible the most important materials that people use most widely and consistently, rather than historic or outdated web content that is only used for reference, research, or recordkeeping.

Comment: Many commenters opposed the proposed archived web content exception because they believe it would result in people with disabilities being denied access in perpetuity to historical information. Several commenters noted that access to archived public documents is key to the public's right to know, petition, and engage in the American democratic process. These commenters said that these legal rights, such as access to public meeting information, should not be abridged on the basis of disability or any other exclusionary reason. Other commenters stated that if recipients do not respond to requests for accessible electronic documents in a timely manner, important information falls under this exception, and any essential documents should not be included in this exception. In addition, commenters said that individuals with disabilities may not know what content they are looking for to make such request for accessible versions. Several commenters stated there will be a negative impact on students, researchers, and other professionals with disabilities who frequently require access to archived content for their studies and livelihoods. One commenter supported the exception, saying that recipients should be encouraged to accommodate people with disabilities so they can access content when requested.

Response: The Department understands the concerns raised by commenters about the burdens that people with disabilities may face because archived web content is not required to conform to WCAG 2.1 Level AA. The Department emphasizes that even if certain content does not have to conform to the technical standard, recipients still need to ensure that their programs and activities offered using web content are accessible to people with disabilities on a case-by-case basis in accordance with their other obligations under section 504. These obligations include making reasonable modifications to avoid discrimination on the basis of disability, ensuring that communications with people with disabilities are as effective as communications with people without disabilities, and providing people with disabilities an equal opportunity to participate in or benefit from the recipient's programs or activities.[166]

The Department emphasizes that web content that is not archived, but instead notifies users about the existence of archived web content and provides users access to archived web content, generally must still conform to WCAG 2.1 Level AA. Therefore, the Department anticipates that members of the public will have information about what content is contained in an archive. For example, a recipient's archive may include a list of links to download archived documents. Under WCAG 2.1 Success Criterion 2.4.4, a recipient would generally have to provide sufficient information in the text of the link alone, or in the text of the link together with the link's programmatically determined link context, so users could understand the purpose of each link and determine whether they want to access a given document in the archive.[167]

The Department continues to believe that the exception appropriately encourages recipients to utilize their resources to make accessible the critical up-to-date materials that are most consistently used to access recipients' programs or activities. The Department believes the exception provides a measure of clarity and certainty for recipients about what is required of archived web content. Therefore, resources that might otherwise be spent making accessible large quantities of historic or otherwise outdated information available on some recipients' websites are freed up to focus on important current and future web content that is widely and frequently used by members of the public. However, the Department emphasizes that the exception is not without bounds. As discussed above, archived web content must meet all four parts of the archived web content definition in order to qualify for the exception. Content must meet the time-based criteria specified in the first part of the definition. The Department believes the addition of the first part of the definition will lead to greater predictability about the application of the exception for individuals with disabilities and recipients. In addition, web content that is used for something other than reference, research, or recordkeeping is not covered by the exception.

Comment: Many commenters pointed out that recipients already have the option to claim fundamental alteration or undue burdens limitations for the subpart. If a recipient cannot argue that making archived documents accessible would result in a fundamental alteration or undue burden, then they should provide access to archived documents via a schedule that prioritizes conversion based on the needs of their constituents. Some commenters suggested that priority should be based on which records are accessed more often, or those that are more chronologically recent. Some commenters mentioned that the burden of proving fundamental alteration or undue burden is on the recipient and the Department should provide clear guidelines on how to satisfy such defenses. One commenter asked about the consequences for noncompliance and encouraged the Department to give recipients ample time and opportunity to correct issues.

Several commenters pointed out that the status quo is that accessible documents are not provided in a timely

[165] *Maintain,* Black's Law Dictionary (11th ed. 2019).

[166] *See* 45 CFR 84.68(b)(1)(ii), (b)(7), 84.77.

[167] *See* W3C, *Web Content Accessibility Guidelines 2.1, Link Purpose (In Context)* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F.*

manner upon request, and requested that if the Department does end up allowing the exception for archived documents, then the Department should define ''timely manner'' to no longer than a few business days. Commenters said the Department should also require that recipients post processes and timelines for accessing inaccessible archived documents.

Some commenters requested that any documents archived after the effective date of this rule be kept in an accessible format.

One commenter said the Department should distinguish between archives that are themselves programs of a recipient (*e.g.,* special digital collections and recordkeeping) versus any information that was originally web content and that may be archived solely for reference (*e.g.,* old calendar events or time-oriented resources kept on an archives section of the website). This commenter stated that when an archive is itself a program, it should be required to be accessible.

Response: The Department's aim in setting forth exceptions was to make sure that individuals with disabilities have ready access to recipients' web content and mobile apps, especially those that are current, commonly used, or otherwise widely needed, while also ensuring that practical compliance with this rule is feasible and sustainable for recipients. The exceptions help to ensure that compliance with this final rule is feasible by enabling recipients to focus their resources on making frequently used or high impact content WCAG 2.1 Level AA compliant first. The Department was mindful of the pragmatic concern that should the final rule require actions that are likely to result in fundamental alterations or undue burdens for large numbers of recipients or large swaths of their content, the rule could in practice lead to fewer improvements for accessibility across the board as recipients encountered these limitations. The Department believes that such a rule could result in recipients prioritizing accessibility of content that is ''easy'' to make accessible, rather than content that is essential, despite the spirit and letter of the rule. The Department believes that clarifying that recipients do not need to focus resources on certain content helps ensure that recipients can focus their resources on the large volume of content not covered by exceptions, as that content is likely more frequently used or up to date.

As discussed above, the Department has decided to keep the archived web content exception in the final rule. After reviewing the range of different views expressed by commenters, the Department continues to believe that the exception appropriately encourages recipients to utilize their resources to make accessible the critical up-to-date materials that are most consistently used to access recipients' programs or activities. The Department believes the exception provides a measure of clarity and certainty for recipients about what is required of archived web content. Therefore, resources that might otherwise be spent making accessible large quantities of historic or otherwise outdated information available on some recipients' websites are freed up to focus on important current and future web content that is widely and frequently used by members of the public.

The Department also declines to treat differently recipients whose primary function is to provide or make available what a commenter perceived as archived web content. The Department reiterates that whether archived web content is retained exclusively for reference, research, or recordkeeping depends on the particular facts and circumstances. The Department believes the exception and definition of archived web content together provide a workable framework for determining whether all types of recipients properly designate web content as archived.

The Department declines to require recipients to adopt procedures and timelines for how individuals with disabilities could request access to inaccessible archived web content covered by the exception. The Department reiterates that, even if content is covered by this exception, recipients still need to ensure that their programs and activities offered using web content are accessible to people with disabilities on a case-by-case basis in accordance with their other obligations under section 504. These obligations include making reasonable modifications to avoid discrimination on the basis of disability, ensuring that communications with people with disabilities are as effective as communications with people without disabilities, and providing people with disabilities an equal opportunity to participate in or benefit from the recipient's programs or activities.[168]

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.85(a) as proposed with no modifications and editing the definition of ''archived web content'' in § 84.10 by adding the following at paragraph (1): ''was created before the date the recipient is required to comply with § 84.84, reproduces paper documents created before the date the recipient is required to comply with § 84.84, or reproduces the contents of other physical media created before the date the recipient is required to comply with § 84.84.'' The provision designated as paragraph (1) in the NPRM will be redesignated as paragraph (2) and the word ''maintained'' will be replaced with ''is retained under.'' In addition, the provisions labelled paragraphs (2) and (3) in the NPRM will be redesignated as paragraphs (3) and (4), respectively.

The Department sought comment on the following questions pertaining to preexisting conventional electronic documents (§ 84.85(b)):

- *Web Accessibility Question 20: Where do recipients make conventional electronic documents available to the public? Do recipients post conventional electronic documents anywhere else on the web besides their own websites?*
- *Web Accessibility Question 21: Would this ''preexisting conventional electronic documents'' exception reach content that is not already excepted under the proposed archived web content exception? If so, what kinds of additional content would it reach?*
- *Web Accessibility Question 22: What would the impact of this exception be on people with disabilities? Are there alternatives to this exception that the Department should consider, or additional limitations that should be placed on this exception? How would foreseeable advances in technology affect the need for this exception?*

The comments and our responses on § 84.85(b) are set forth below.

Comment: Some commenters stated that preexisting conventional documents can easily be made accessible, such as by using .doc formats as opposed to .pdf or saving a .pdf in a more accessible manner. Some commenters wanted to broaden this exception to cover preexisting multimedia content and documents produced by government entities. Those commenters reasoned that documents provided by government entities may have statutory limitations that prevent changes and recipients would have no control over or ability to change the content of such documents. Another commenter appreciated the exception because they believe that without the exception recipients would be forced to delete a significant amount of helpful content from their websites. This commenter urged HHS to except content posted on platforms such as YouTube from coverage.

[168] *See* 45 CFR 84.68(b)(1)(ii), (b)(7), 84.77.

Commenters listed types of conventional electronic documents made available to the public such as PDF, brochures, announcements, and slides shows on websites, cloud drives, file sharing sites, and cloud document platforms. Commenters said recipients use social media which allows the posting of links, which can include links to the recipient's own website. Conventional electronic documents can be attached to the social media post themselves in limited circumstances. One commenter recommended changing the wording of exception to include documents that have been posted to sites other than the recipient's website (such as cloud drives and social media).

A State governor said the exception is too broad and proposed limiting the exception to archived documents that are no longer in regular and ongoing use to avoid excessive inaccessible legacy content.

Response: The Department does not intend to broaden this proposed exception at this time, because the exception at § 84.85(a) covers archived web content, the definition of which is not limited to documents.[169] Web content that recipients provide or make available must conform to WCAG 2.1 Level AA unless covered by an exception. That includes videos that a recipient creates.

The Department appreciates commenters' discussions of the types of conventional documents that recipients use and how to make them accessible. Preexisting conventional electronic documents are covered by this exception unless they are currently used to apply for, gain access to, or participate in a recipient's programs or activities.

The Department continues to believe that the exception provides an important measure of clarity and certainty for recipients as they initially consider how to address all the various conventional electronic documents provided and made available through their web content and mobile apps. The exception will allow recipients to primarily focus their resources on developing new conventional electronic documents that are accessible as defined under this rule and remediating preexisting conventional electronic documents that are currently used to apply for, gain access to, or participate in their programs or activities. In contrast, recipients will not have to expend their resources on identifying, cataloguing, and remediating preexisting conventional electronic documents that are not currently used to apply for, gain access to, or participate in the recipients' programs or activities.

The Department modified the language of this exception from the NPRM in ways that are relevant to the comment about the location of the conventional electronic documents, including social media sites and cloud drives. In the NPRM, the Department specified that the exception applied to conventional electronic documents ''created by or for a recipient'' that are available ''on a recipient's website or mobile app.'' The Department believes the language ''created by or for a recipient'' is no longer necessary in the regulatory text of the exception itself because the Department updated the language of § 84.84 to clarify the overall scope of content generally covered by the rule. In particular, and, as explained above, to make clear that recipients cannot delegate away their accessibility responsibilities, the text of § 84.84(a)(1) and (2) now states that the rule applies to all web content and mobile apps that a recipient provides or makes available either ''directly, or through contractual, licensing, or other arrangements.'' Section 84.85(b), which is an exception to the requirements of § 84.84, is therefore limited by the new language added to the general section.

In addition, the Department removed the phrase ''members of the public'' from the language of the exception in the proposed rule for consistency with the edits to § 84.84 of the section 504 regulation and title II of the ADA, as described above.

Comment: Several commenters pointed out that there may be a need for documents that fall under this exception because, while they are not used to apply for, gain access to, or participate in a recipient's programs or activities, they are important for understanding the recipient's programs, activities, and services. One commenter noted that ''apply for, gain access to, or participate in a recipient's services, programs, or activities'' may not be consistently interpreted among recipients, and that documents with information about understanding the recipient's overall programs and activities, research-related documents, directives on health care payment, coding, or coverage can govern medical decisions long after they are published. Commenters noted that disputes related to health care claims can take years to solve, making existing documents relevant for such claims. Commenters noted that even if updated, new documents may not replace older versions in all circumstances, and partial revisions to existing documents make it necessary for both versions to be accessible for comparison.

One commenter stated that the Department adequately addressed concerns about whether supporting information for conventional documents will be accessible with the statement ''a recipient must not only make a new patient form accessible, but it must also make accessible other materials that may be needed to complete the form, understand the process, or otherwise take part in the program.''

Response: Whether a conventional electronic document is currently used to apply for, gain access to, or participate in a recipient's programs or activities is a fact-specific analysis. For example, one commenter questioned whether a document containing a recipient's directives on health care payments would be covered by the exception if the document did not otherwise discuss a particular program or activity. The Department anticipates that the exception would likely not cover such a document because the document is likely used as instructions for making payments to the recipient as part of the recipient's program and activity of collecting payments for health services it provides. The Department provides additional information about how the exception applies to documents that provide instructions or guidance below. Another example is an informational document containing a recipient hospital's description of the accessibility features available throughout its hospital building. The Department anticipates that the exception would likely not cover such a document. One of the recipient's programs and activities is maintaining its building, including the building's accessibility features. An individual with a disability who accesses the document to understand the hospital's accessibility features before going to the hospital to visit a relative receiving treatment there would be currently using the document to gain access to the hospital's building.

Additionally, the Department notes that preexisting documents are also not covered by the exception if they provide instructions or guidance related to other documents that are directly used to apply for, gain access to, or participate in the recipient's programs or activities. Therefore, in addition to making a preexisting PDF application for benefits conform with WCAG 2.1 Level AA, a recipient would also have to make other preexisting documents conform with WCAG 2.1 Level AA if they may be needed to obtain the benefits, complete the application, understand the process, or otherwise take part in the program, such as application instructions,

[169] *See* § 84.10.

manuals, and guides, such as ''Questions and Answers'' documents.

The Department recognizes that there may be some overlap between the content covered by the archived web content exception and the exception for preexisting conventional electronic documents. The Department notes that if web content is covered by the archived web content exception, it does not need to conform to WCAG 2.1 Level AA to comply with this rule, even if the content fails to qualify for another exception, such as the preexisting conventional electronic document exception. For example, after the date a recipient college is required to comply with this rule, its health clinic website may still include PDF documents containing the schedules from academic year 2017–2018 that were posted in non-archived areas of the website in the summer of 2017. Those PDFs may be covered by the preexisting conventional electronic documents exception because they were available on the college's health clinic website prior to the date it was required to comply with this rule, unless they are currently used to apply for, gain access to, or participate in a recipient's programs or activities, in which case, as discussed in this rule, they would generally need to conform to WCAG 2.1 Level AA. However, if the college moved the PDFs to an archived area of its health clinic site and the PDFs satisfied all parts of the definition of archived web content, the documents would not need to conform to WCAG 2.1 Level AA, regardless of how the preexisting conventional electronic document exception might otherwise have applied, because the content would fall within the archived web content exception.

Also, because the exception only applies to preexisting conventional electronic documents, it would not cover documents that are open for editing if they are changed or revised after the date a recipient is required to comply with this rule. For example, a school may maintain an editable word processing file, such as a Google Docs file, that lists the dates on which the school held school board meetings. The school may post a link to the document on its website so members of the public can view the document online in a web browser, and it may update the contents of the document over time after additional meetings take place. If the document was posted to the school's website prior to the date it was required to comply with the rule, it would be a preexisting conventional electronic document unless the school added new dates to the document after the date it was required to comply with this rule. If the school made such additions to the document, the document would no longer be preexisting. Nevertheless, there are some circumstances where conventional electronic documents may be covered by the exception even if copies of the documents can be edited after the date the recipient is required to comply with this rule. For example, a recipient may post a Microsoft Word version of a flyer on its website prior to the date it is required to comply with this rule. A member of the public could technically download and edit that Word document after the date the recipient is required to comply with the rule, but their edits would not impact the ''official'' posted version. Therefore, the official version would still qualify as preexisting under the exception. Similarly, PDF files that include fillable form fields (*e.g.,* areas for a user to input their name and address) may also be covered by the exception so long as members of the public do not edit the content contained in the official posted version of the document. However, as discussed below, the exception does not apply to documents that are currently used to apply for, gain access to, or participate in a recipient's programs or activities. The Department notes that whether a PDF document is fillable may be relevant in considering whether the document is currently used to apply for, gain access to, or participate in a recipient's programs or activities. For example, a PDF form that must be filled out and submitted when submitting medical information to a health provider is currently used to apply for, gain access to, or participate in a recipient's programs or activities, and therefore would not be subject to the exception for preexisting conventional electronic documents.

Comment: Commenters mentioned several populations that would be affected, including participants in adult education programs that may need to use another recipient's document for tools, skills and programs for future employment training; citizens who will be unable to petition the government for redress of grievances due to inaccessible meeting presentation documents; and researchers who will not have access to research publications, public health reports, and reports about community health needs.

Several commenters pointed out that people with disabilities must disclose their disability in requests for accessible versions of preexisting conventional electronic documents and wait for the recipient to remediate the document. One commenter said that a recipient's time is better spent on making sure new conventional electronic documents are accessible rather than historical data.

Several commenters pointed out that small recipients will have an additional three years to publish inaccessible materials, many of which will not be archived for several years. These commenters believed that these timeframes could be interpreted by these recipients to mean that those documents do not need to be made accessible.

One commenter stated that documents that meet the preexisting conventional document exception but are no longer applicable to a current program or activity should be archived. The commenter wrote that the remaining documents included under this exception should be limited, if any. Another commenter said that documents that recipients provide are often ''living'' documents, meaning they will be edited often, but not archived for several years. A different commenter expressed appreciation of the Department's clarification that if a recipient updates an otherwise covered document after the effective date of this rule, it is no longer considered preexisting.

One commenter noted that there are already advances in technology that allow for modification of preexisting conventional electronic documents.

Response: The Department understands the concerns raised by commenters about the potential burdens that individuals with disabilities may face because some conventional electronic documents covered by the exception are not accessible. The Department emphasizes that even if certain content does not have to conform to the technical standard, recipients still need to ensure that their programs and activities offered using web content are accessible to people with disabilities on a case-by-case basis in accordance with their other obligations under section 504. These obligations include making reasonable modifications to avoid discrimination on the basis of disability, ensuring that communications with people with disabilities are as effective as communications with people without disabilities, and providing people with disabilities an equal opportunity to participate in or benefit from the recipient's programs or activities.[170]

The Department agrees that recipients may choose to archive their existing conventional electronic documents if they meet the definition of archived web content in § 84.10. The Department also agrees that if a recipient changes or

[170] *See* 45 CFR 84.68(b)(1)(ii), (b)(7), 84.77.

revises a preexisting document following the date it is required to comply with the rule, the document would no longer be ''preexisting'' for the purposes of the exception.

Summary of Regulatory Changes

For the reasons set forth above, the comments received, and other changes throughout this rulemaking, the Department is making limited modifications to § 84.85(b). As discussed above, the Department is eliminating the phrase ''created by or for a recipient'' because such situations are now addressed by the ''directly or through contractual, licensing, or other arrangements'' language inserted into § 84.84(a) and (b). The Department is also replacing ''on a recipient's website or mobile app'' with ''as part of a recipient's web content or mobile apps'' to ensure consistency with other parts of the regulatory text by referring to ''web content'' rather than ''websites.'' In addition, the Department removed the phrase ''members of the public'' from the language of the exception for consistency with the edits to § 84.84 of the section 504 regulation and title II of the ADA.

The Department sought comment on the following questions pertaining to web content posted by a third party (§ 84.85(c)):

- *Web Accessibility Question 23: What types of third-party web content can be found on websites of recipients? How would foreseeable advances in technology affect the need for creating an exception for this content? To what extent is this content posted by the recipients themselves, as opposed to third parties? To what extent do recipients delegate to third parties to post on their behalf? What degree of control do recipients have over content posted by third parties, and what steps can recipients take to make sure this content is accessible?*
- *Web Accessibility Question 24: What would the impact of this exception be on people with disabilities?*

The comments and our responses on § 84.85(c) are set forth below.

Comment: Commenters stated that social media profiles of recipients allow for public comments from news about emergencies like disasters or shooters and can be more current than the local news coverage. Commenters describe social media as spaces used to complain about community conditions, get advice, and get organized. Commenters also stated that social media is used to understand new programs, health policy, public comments, and public contracts. Some commenters found that tools for accessibility provided on social media platforms may not be sufficient for accessibility. Another commenter recommended requiring training on how to use these third-party accessibility features and that such trainings should be documented.

Commenters mentioned situations, other than through social media, where web content is posted by a third party on a recipient's website such as when recipients post forums for public comments, promote individuals' rights to petition the government for redress of grievances, solicit real-time feedback during public meetings, or seek bids for contracts on third-party platforms. Other commenters mentioned teachers assigning work through a class message board that may require students to reply with video, essay, wiki page or other work. Another commenter mentioned scheduling tools, maps, calendars, and payment systems. One commenter said that third-party content could be uploaded to a case docket and the inaccessibility of such posting could deny the individual the right to a fair hearing as well as equal employment in the legal profession.

Some commenters said that if this exception is eliminated, recipients can take steps to make sure content is accessible by changing settings, setting rules, and prompting users to include alt text.

A few commenters said they are not able to control third-party content and supported this exception. Those commenters said it's up to the third-party to make content accessible. Some commenters said recipients often receive materials from third parties, including legal documents like signed contracts, that could be materially altered if the recipient makes them accessible. One commenter said that enforcing accessibility may force recipients to remove resources otherwise helpful to their enrollees such as population health management programs. Another commenter agreed with the exception but thought that the recipient should be able to provide an accessible system for the general structure and that text-only postings should be easy to make accessible and recommend that this level of accessibility be required.

One commenter requested clarification on (1) criteria for how recipients can distinguish among third-party content that may or may not allow members of the public to participate in or benefit from the recipient's programs or activities; and (2) whether the technical standard requirements would apply to third-party materials that are linked within a recipient's website such as other websites or non-text content.

Some commenters voiced concerns with the challenge of meeting requirements in the proposed time frame as they have already procured most of their software for development. One commenter recommended that OCR conduct additional outreach and educational activities to software and other vendors to ensure that they know about technology accessibility standards.

Some other commenters requested that the Department edit part of the exception because while third-party content can be located on the recipient's website, it may not always be ''posted'' by the third-party entity.

Response: The Department appreciates the responses, particularly those that identified situations where a third party may post content on a recipient's website. The final rule includes this exception in recognition of the fact that individuals other than a recipient's agents sometimes post content on a recipient's web content and mobile apps. For example, members of the public may sometimes post on a recipient's online message boards, wikis, social media, or other web forums, many of which are unmonitored, interactive spaces designed to promote the sharing of information and ideas. Members of the public may post frequently, at all hours of the day or night, and a recipient may have little to no control over the content that the third party posted. In some cases, a recipient's website may include posts from third parties dating back many years, which are likely of limited, if any, relevance today. Because recipients often lack control over this third-party content, it may be challenging (or impossible) for them to make it accessible. Moreover, because this third-party content may be outdated or less frequently accessed than other content, there may be only limited benefit to requiring recipients to make this content accessible. An example would be a recipient website that includes a comment section that allows members of the public to post reviews or responses.

Based on the comments received, the Department believes there may be confusion, especially among recipients, as to what content would be excepted. The exception in § 84.85(c) does not apply to content posted by the recipient itself, or posted on behalf of the recipient due to contractual, licensing, or other arrangements, even if the content was originally created by a third party. For example, many recipients post third-party content on their websites, such as calendars, scheduling tools, maps, reservations systems, and payment systems that were developed

by an outside technology company. Sometimes a third party might even build a recipient's website template on the recipient's behalf. To the extent a recipient chooses to rely on third-party content on its website in these ways, it must select third-party content that meets the requirements of § 84.84. This is because a recipient may not delegate away its obligations under section 504.[171] If a recipient relies on a contractor or another third party to post content on the recipient's behalf, the recipient retains responsibility for ensuring the accessibility of that content.

The Department has added language to the third-party posted exception in the final rule to make clear that the exception does not apply where a third party is posting on behalf of the recipient. The language provides that the exception does not apply if ''the third party is posting due to contractual, licensing, or other arrangements with the recipient.'' The Department added this language to make clear that the exception only applies where the third-party posted content is independent from the actions of the recipient—that is, where there is no arrangement under which the third party is acting on behalf of the recipient. If such an arrangement exists, the third-party content is not covered by the exception and must be made accessible in accordance with this rule. This point is also made clear in language the Department added to the general requirements of § 84.84, which provides that recipient shall ensure web content and mobile apps that the recipients provide or make available, ''directly or through contractual, licensing, or other arrangements,'' are readily accessible to and usable by individuals with disabilities. The Department decided to add the same clarification to the exception for third-party posted content because this is the only exception in the final rule that applies solely based upon the identity of the poster (whereas the other exceptions identify the type of content at issue), and the Department believes clarity about the meaning of ''third party'' in the context of this exception is critical to avoid the exception being interpreted overly broadly. The Department believes this clarification is justified by the concerns raised by commenters.

The majority of the comments received addressed instances in which a State or local government may receive third party posts on public forum matters from members of the public, not instances where health and human service providers receive third party posts on their own websites. Many of the comments also focused on the social media posts of recipients that may receive third party comments over which the recipients have no control.

The Department is committed to providing guidance on this rulemaking once finalized as appropriate.

Comment: Many commenters disagreed with this exception. These commenters said that people would lose access to time-sensitive information, employment opportunities, educational content, and robust opportunities to participate in public feedback sessions. They also said that people with disabilities would not be able to participate in discussions of shared grievances and concerns about their communities that will lead to lack of ability to seek redress for those grievances. One commenter said that ADA covered entities may be less mindful of their ADA obligations if they are under no pressure from recipients to make certain content accessible. A different commenter remarked on the web accessibility standard differences between ADA title III entities posting on section 504 third-party pages, saying that because title III does not have specific web accessibility standards, third-party pages are less likely to make their content accessible if the section 504 entity doesn't pressure them to do so.

Several commenters expressed support for this exception. One commenter thought it was unreasonable to ask the recipient to police third-party content. One commenter was not sure how to pose a solution to inaccessible third-party content being posted, but thought that posting accessibility guidelines on their websites for third parties to use could be feasible. Another commenter thought that lack of access to third-party content was merely an annoyance to people with disabilities that could potentially become problematic if the recipient relies on the public to provide their customer support.

Response: After reviewing the comments, the Department emphasizes at the outset the narrowness of this exception—any third-party content that is posted due to contractual, licensing, or other arrangements with the recipient would not be covered by this exception. The Department sometimes refers to the content covered by this exception as ''independent'' or ''unaffiliated'' content to emphasize that this exception only applies to content that the recipient has not contracted, licensed, or otherwise arranged with the third party to post. This exception would generally apply, for example, where the recipient enables comments from members of the public on its social media page and third-party individuals independently comment on that post.

The Department recognizes that the inclusion of this exception means web content posted by third parties may not consistently be accessible by default. The Department emphasizes that even if certain content does not have to conform with the technical standard, recipients still need to ensure that their programs and activities offered using web content and mobile apps are accessible to people with disabilities on a case-by-case basis in accordance with their existing obligations under section 504. These obligations include making reasonable modifications to avoid discrimination on the basis of disability, ensuring that communications with people with disabilities are as effective as communications with people without disabilities, and providing people with disabilities an equal opportunity to participate in or benefit from the recipient's programs or activities.[172]

Additionally, the Department wishes to clarify that while the exception for third-party posted content applies to that content which is posted by an independent third party, the exception does not apply to the authoring tools and embedded content provided by the recipient, directly or through contractual, licensing, or other arrangements. Because of this, authoring tools, embedded content, and other similar functions provided by the recipient that facilitate third-party postings are not covered by this exception and must be made accessible in accordance with the rule. Further, recipients should consider the ways in which they can facilitate accessible output of third-party content through authoring tools and guidance.

With respect to comments pertaining to title III of the ADA, the Department emphasizes that this proposed rulemaking only addresses recipients' obligations under section 504.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.85(c) with limited modifications to clarify that the exception does not apply where a third party is posting on behalf of the recipient due to contractual, licensing, or other arrangements. This point is also made clear in the general requirements

[171] *See* 45 CFR 84.4, redesignated as § 84.68(b)(1) (prohibiting discrimination directly or through a contractual, licensing, or other arrangement that would provide an aid, benefit, or service to a qualified individual with a disability that is not equal to that afforded others).

[172] *See* 45 CFR 84.68(b)(1)(ii), (b)(7), 84.77.

of § 84.84, which provides that recipients shall ensure web content and mobile apps that the recipients, ''directly or through contractual, licensing, or other arrangements'' provide or make available are readily accessible to and usable by individuals with disabilities.

The Department sought comment on the following questions pertaining to linked third-party web content (§ 84.85(d)):

- *Web Accessibility Question 25: Do recipients link to third-party web content to allow members of the public to participate in or benefit from the recipients' programs or activities? If so, to what extent does the third-party web content that recipients use for that purpose conform with WCAG 2.1 Level AA?*
- *Web Accessibility Question 26: What would the impact of this exception be on people with disabilities, and how would foreseeable advances in technology affect the need for this exception?*
- *Web Accessibility Question 27: What types of external mobile apps, if any, do recipients use to provide access to their programs and activities to members of the public, and how accessible are these apps? While the Department has not proposed an exception to the requirements proposed in § 84.84 for recipients' use of external mobile apps, should the Department propose such an exception? If so, should this exception expire after a certain time, and how would this exception impact persons with disabilities?*

The comments and our responses on § 84.85(d) are set forth below.

Comment: Many commenters opposed this exception. Several commenters believed it was important that third parties share some of the responsibility for making their content accessible. Commenters provided examples of recipients linking to third-party web content such as a public health department providing up to date information about a shortage of a certain medication and identifying which pharmacies still have a supply. Some commenters said that recipients should only link content that is accessible on their own website.

Several commenters were in favor of this exception. One commenter believed that enforcing accessibility may force recipients to remove resources otherwise helpful to their enrollees such as a population health management program tailored to certain enrollees.

Response: After consideration of the comments received, the Department believes that inclusion of this exception is unnecessary, would result in confusion, and that removing the exception more consistently aligns with the language of section 504 and the Department's intent in proposing the exception in the NPRM. The Department believes that the proper analysis is whether a recipient has ''directly, or through contractual, licensing, or other arrangements,'' provided or made available the third-party content. This means that, for example, when a recipient posts links to third-party web content on the recipient's website, the links located on the recipient's website and the organization of the recipient's website must comply with § 84.84. Further, when a recipient links to third-party web content that is provided by the recipient, directly or through contractual, licensing, or other arrangements, the recipient is also responsible for ensuring the accessibility of that linked content. However, when recipients link to third-party websites, unless the recipient has a contractual, licensing, or other arrangement with the website to provide or make available content, those third-party websites are not covered by section 504, because they are not programs or activities provided or made available by recipients, and thus recipients are not responsible for the accessibility of that content. By deleting this exception, the Department will maintain its original intent without unnecessary confusion for recipients or members of the public.

Rather than conduct a separate analysis under the proposed exception in the NPRM, the Department believes the simpler and more legally consistent approach is for recipients to assess whether the linked third-party content reflects content that is covered under this rule to determine their responsibility to ensure the accessibility of that content. If that content is covered, it must be made accessible in accordance with the requirements of § 84.84. However, if the content is not provided or made available by a recipient, directly or through contractual, licensing, or other arrangements, even though the recipient linked to that content, the recipient would not be responsible for making that content accessible. The recipient would still need to ensure the links themselves are accessible, but not the unaffiliated linked third-party content.

Comment: Commenters who opposed this exception expressed the view that if the Department moves forward with this exception, it will undermine recipients' attempts to bring their vendors and partners into compliance. One commenter said that only posting accessible third-party content will reduce the chance of adverse impact on people with disabilities. This commenter believes that the provider writing the third-party content will benefit financially from such linkage and that this is a negotiating aspect for accessibility. Several commenters said that contracts with third parties should include accessibility requirements.

One commenter proposed that if the linked content is important to understanding or providing context to users of the recipient's website, an alternate method of access should be provided. For example, the commenter suggested using a statement like ''Please follow this link for relevant context or contact our customer support line if you need help understanding this information.''

Response: The Department reiterates that rather than conduct a separate analysis under the proposed exception in the NPRM, the simpler and more legally consistent approach is for recipients to assess whether the linked third-party content reflects content that is covered under this rule to determine their responsibility to ensure the accessibility of that content. If that content is covered, it must be made accessible in accordance with the requirements of § 84.84. However, if the content is not provided or made available by a recipient, directly or through contractual, licensing, or other arrangements, even though the recipient linked to that content, the recipient would not be responsible for making that content accessible. The recipient would still need to ensure the links themselves are accessible, but not the unaffiliated linked third-party content. Whether third-party linked content is covered by the requirements of § 84.84 depends on the facts and circumstances. In instances where linked third-party content provides instructions or guidance related to the recipient's programs and activities, the linked third-party content is likely subject to the requirements of § 84.84.

Comment: Most commenters thanked HHS for not including an exception for mobile apps. Commenters mentioned situations where external mobile apps would provide access to programs and activities, including but not limited to: telehealth, patient communication, appointment booking, bill payment, test results, medication information, tracking transit vehicles like non-emergency medical transportation, e-books, event announcements, tickets, food service ordering, media, and entertainment.

One commenter said the accessibility requirements should be included in the

contracts between recipients and third-party app developers. Another stated that content created should also follow accessibility standards in apps. Another commenter said that people who are deaf, deafblind, deafdisabled, late-deafened, and hard of hearing are often unable to seek telehealth medical advice due to the inability of the conferencing platform to support sign language interpretation, video relay service, or captioning.

One commenter encouraged HHS to include an exception for external mobile apps.

Response: The Department appreciates the comments. As discussed above, the Department has removed the linked third-party web content exception from the final rule altogether.

The Department recognizes that many recipients use mobile apps that are developed, owned, and operated by third parties, such as private companies, to allow the public to access the recipient's programs and activities. This part of the analysis refers to mobile apps that are developed, owned, and operated by third parties as ''external mobile apps.'' In the final rule, external mobile apps are subject to § 84.84 in the same way as mobile apps that are developed, owned, and operated by a recipient. Accordingly, if a recipient, directly or through contractual, licensing, or other arrangements, provides or makes available an external mobile app, that mobile app must comply with § 84.84 unless it is subject to one of the exceptions outlined in § 84.85.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are deleting proposed § 84.85(d).

Proposed § 84.85(e) contained an exception for password-protected class or course content used by postsecondary institutions with limitations based on when the recipient knew or should have known that a student with a disability is preregistered for a course or has enrolled in a course after the start of the academic term and will be unable to access the password-protected class or course content due to disability.

The Department invited comment on the following questions pertaining to password-protected class or course content:

- *Web Accessibility Question 28: Are there particular issues relating to the accessibility of digital books and textbooks that the Department should consider in finalizing this rule? Are there particular issues that the Department should consider regarding the impact of this rule on libraries?*
- *Web Accessibility Question 29: How difficult would it be for postsecondary institutions to comply with this rule in the absence of this exception?*
- *Web Accessibility Question 30: What would the impact of this exception be on people with disabilities?*
- *Web Accessibility Question 31: How do postsecondary institutions communicate general information and course-specific information to their students?*
- *Web Accessibility Question 32: Do postsecondary institutions commonly provide parents access to password-protected course content?*
- *Web Accessibility Question 33: The proposed exception and its limitations are confined to content on a password-protected or otherwise secured website for students enrolled in a specific course. Do postsecondary institutions combine and make available content for particular groups of students (e.g., newly admitted students or graduating seniors) using a single password-protected website and, if so, should such content be included in the exception?*
- *Web Accessibility Question 34: On average, how much content and what type of content do password-protected course websites of postsecondary institutions contain? Is there content posted by students or parents? Should content posted by students or parents be required to be accessible and, if so, how long would it take a postsecondary institution to make it accessible?*
- *Web Accessibility Question 35: How long would it take to make course content available on a recipient's password-protected or otherwise secured website for a particular course accessible, and does this vary based on the type of course? Do students need access to course content before the first day of class? How much delay in accessing online course content can a student reasonably overcome in order to have an equal opportunity to succeed in a course, and does the answer change depending on the point in the academic term that the delay occurs?*
- *Web Accessibility Question 36: To what extent do educational institutions use or offer students mobile apps to enable access to password-protected course content? Should the Department apply the same exceptions and limitations to the exceptions under proposed § 84.85(e) introductory text and (e)(1) and (2), respectively, to mobile apps?*
- *Web Accessibility Question 37: Should the Department consider an alternative approach, such as requiring that all newly posted course content be made accessible on an expedited time frame, while adopting a later compliance date for remediating existing content?*

The comments and our responses on § 84.85(e) are set forth below.

Comment: Several commenters mentioned that DOJ and ED provided guidance in early 2010 which led most public colleges and universities to develop universally designed courses using a framework that outlines methods of designing courses to make them accessible for all students, including students with disabilities. Commenters stated that Federal agencies have also funded technical assistance resources for colleges and universities; such resources have included information about how to implement coordinated systems for the timely provision of accessible materials and technologies and some of these resources touch on improving access capabilities to Science, Technology, Engineering, Math (STEM) materials.

Many commenters commented on how difficult it is for a college to wait until a student enrolls in a course and then have to retroactively attempt to fix inaccessible courses. Others mentioned that several colleges and universities already have policies requiring that new digital content be made accessible subject only to fundamental alteration and undue burden limitations. One commenter stated that simple courses may take five days to remediate while more complex courses with visual materials, audio materials, or other inaccessible documents will take significantly longer. This commenter added that if more than one course needs to be remediated, then the five-day period will no longer be feasible for simple courses. One commenter said that remediating a textbook can take the same amount of time as designing a new course. That same commenter mentioned that large videos can take a lot of time to caption and provide audio content on, even when outsourcing. One commenter mentioned that planning and coordination of the conversion of accessible content can take two to three hours per course.

Another commenter mentioned that students may need access to the course prior to the official start of the semester. Several commenters talked about the impact of a student dropping and then adding a course during the beginning of the semester.

One commenter asked who the responsible party is when a high school student enrolls in college courses in situations of dual enrollment.

One commenter mentioned that when requirements for captioned television shows were first mandated, similar

concerns were expressed about the difficulty of coming into compliance with new regulations, but now captioned television is part of the industry norm.

Some commenters supported the exception.

Response: Having reviewed the public comments, the Department believes it is appropriate, as many commenters suggested, not to include the previously proposed course content exceptions in the final rule. For many of the reasons noted by commenters, the Department concludes that the proposed exceptions would not meaningfully ease the burden on educational institutions and would significantly exacerbate educational inequities for students with disabilities. The Department concludes that the proposed exceptions would have led to an unsustainable and infeasible framework for recipients to make course content accessible, which would not have resulted in reliable access to course content for students with disabilities. As many commenters noted, it would have been extremely burdensome and sometimes even impossible for educational institutions to comply consistently with the rapid remediation timeframes set forth in the limitations to the proposed exceptions in the NPRM, which would likely have led to widespread delays in access to course content for students with disabilities. While extending the remediation timeframes might have made it more feasible for educational institutions to comply under some circumstances, this extension would have commensurately delayed access for students with disabilities, which would have been harmful for the many reasons noted by commenters. The Department believes that it is more efficient and effective for educational institutions to use the two- or three-year compliance timeframe to prepare to make course content accessible proactively, instead of having to scramble to remediate content reactively.

Accordingly, under the final rule, password-protected course content will be treated like any other content and will generally need to conform to WCAG 2.1 Level AA. To the extent that it is burdensome for recipients to make all of their content, including course content, accessible, the Department believes the rule contains a series of mechanisms that are designed to make it feasible for these institutions to comply, including the delayed compliance dates discussed in § 84.84, the other exceptions discussed in § 84.85, the provisions relating to conforming alternate versions and equivalent facilitation discussed in §§ 84.86 and 84.87, the fundamental alteration and undue burdens limitations discussed in § 84.88, and the approach to measuring compliance with the rule discussed in § 84.89.

Comment: Many commenters said this exception would reduce a person with a disability's opportunity to change courses, exclude them from education, and give them fewer opportunities to succeed than their peers. Several commenters mentioned that this exception would put a student with a disability five days behind their peers and that for a January or summer-term course, a five-day delay could be a third of the course. Commenters also mentioned that due to the delays in graduation, students faced loss of earning from being unable to enter the workforce which was a cost that taxpayers took on through vocational rehabilitation funds, Federal student loans, and Pell grants.

Some of the commenters mentioned a case where two blind students were excluded from an educational program because of inaccessible classroom materials, textbooks, websites, and educational applications. These commenters pointed out that the two students could not independently enroll in courses, nor could they use library databases, and were forced to either drop classes or accept a lower grade.

A commenter discussed instances where most of the classes in a law school were not made accessible, but in one class where they were accessible, it took six to eight weeks for a student to receive them. This student had to extend her studies and the cost was split between the student and the State's vocational rehabilitation program.

Some commenters pointed to the DOJ's May 19, 2023, *Dear Colleague Letter on Online Accessibility at Postsecondary Institutions,* saying that postsecondary institutions are already required to make all course materials accessible under the ADA.

Response: The Department appreciates the comments and notes the important concerns for students with disabilities when postsecondary institutions do not make their courses accessible or do not provide accessible materials in a timely manner. As discussed, the Department has decided not to include proposed § 84.85(e) in the final rule.

The comments on this issue illustrate the challenges associated with setting remediation timeframes in this context. If the Department were to shorten the remediation timeframes, it would make it even harder for educational institutions to comply, and commenters have already indicated that the previously proposed remediation timeframes would not be workable for those institutions. If the Department were to lengthen the remediation timeframes, it would further exacerbate the inequities for students with disabilities that were articulated by commenters. The Department believes the better approach is to not include the course content exceptions in the final rule to avoid the need for educational institutions to make content accessible on an expedited timeframe on the back end, and to instead require recipients to treat course content like any other content covered by this rule.

Comment: Commenters mentioned a wide variety of communication vehicles including emails, website postings, social media, mobile apps, phone video calls, live orientation events, in-class announcements, and learning management systems, that postsecondary institutions use to communicate information to their students.

Response: The Department appreciates these comments and notes that the definitions of ''web content'' and ''mobile apps'' describe the content that is covered under this rule.

Comment: Concerning whether postsecondary institutions provide parents with access to course content, one commenter mentioned the Family Educational Rights and Privacy Act which gives students the ability to allow parents and guardians limited access to student information including mid-semester and final grades. The commenter was concerned about access for parents with disabilities given permission under this law to view such content.

Response: The Department appreciates these comments. As noted above, the Department will not adopt this proposed exception.

Comment: On whether postsecondary institutions combine and make available content for particular groups, several commenters mentioned the learning management systems for general groups of students and said that password-protected websites should be required to meet WCAG guidelines.

Response: The Department appreciates these comments and notes that this final rule will not adopt the previously proposed exceptions for password-protected course content. Password-protected course content will therefore need to be accessible, in accordance with this final rule.

Comment: On how much and what content password-protected course websites contain, commenters listed electronic textbooks, slide decks, PDFs and digital articles, shared documents,

video and audio recordings, announcements, message boards, discussion boards, blogs, spreadsheets, assignments, tables and graphs, interactive labs, links to education sites, and interactive websites.

Response: The Department appreciates these comments and notes that the breadth of content that postsecondary institutions offer to students is one of the reasons that the Department will not include this proposed exception in the final rule.

Comment: One commenter stated that courses will likely take more than five days to remediate, especially if they rely on electronic textbooks and large videos.

Another commenter mentioned that students may need access to the course prior to the official start of the semester. Several commenters talked about the impact of a student dropping and then adding a course during the beginning of the semester.

One commenter asked who the responsible party is when a high school student enrolls in college courses in situations of dual enrollment.

Response: The Department appreciates these comments and, for the reasons already discussed, this rule will not adopt the previously proposed course content exceptions that included this five-day remediation period.

Comment: Some commenters supported applying the exceptions proposed at § 84.85(e) introductory text and (e)(1) and (2) to mobile apps. Other commenters disagreed saying that there should be no exceptions and that there are already federally funded resources and technical assistance that support the acquisition of software and applications that are accessible and interactive with assistive technology.

Response: The Department appreciates these comments. For the reasons previously noted, the final rule does not include the exception previously proposed at § 84.85(e).

Comment: On alternatives for this exception, including making newly posted course content accessible on an expedited time frame, commenters stated that priority should be given to entry-level courses, high enrollment courses, courses of the majors that students with disabilities are currently enrolled in, and courses with high drop, withdrawal and failing grade rates. Others mentioned being proactive about providing accessibility training to students and employees.

One commenter encouraged HHS to hold third-party vendors accountable for creating accessible products and suggested funding staff positions for course compliance reviews and remediation work. One commenter said that postsecondary institutions should be required to make student-provided visual and audio content accessible to students with disabilities.

Response: The Department appreciates these comments. For the reasons discussed, the Department is not including the proposed exception in the final rule and will not adopt the alternative approaches suggested. Also, the Department notes that the definitions of ''web content'' and ''mobile apps'' as well as the rule's exceptions and limitations describe the content that is covered under this rule.

Comment: Many commenters said that digital books and textbooks should be accessible to people with disabilities. Several commenters specifically said that digital books and textbooks should conform to WCAG 2.2 accessibility standards, and that e-readers, learning management systems, and other technology that delivers digital books and textbooks must also be accessible.

Many commenters wanted HHS to clarify that while schools or libraries may ultimately be responsible for providing access to digital books and textbooks, the third-party publishers play a significant role in the accessibility of textbooks and digital books. Some commenters indicated that if all libraries and schools required publishers to deliver accessible versions, then this would reduce the work that goes into converting them into accessible formats, often done by scanning pages and saving as PDF files. These commenters also said that schools and libraries are currently put into positions of having to procure, create, or break digital rights management protections to provide accessible textbooks and digital books.

One commenter mentioned a study that found that out of a random sampling of 355 Open Educational Resource materials, only two passed an accessibility test, and that the accessibility barriers were either caused by the author or creator or the authoring software and publishing tools.

One commenter mentioned additional challenges with STEM materials as they have complex equations, graphics, maps, and spatial educational materials and alt text may not be sufficient to convey the concept of these items.

Commenters suggested when a course is updated to use a new textbook (or a new edition of an existing textbook), the Department should require a recipient to select the most accessible option that meets the instructional goals. Commenters said educational institutions should be responsible for providing accessible alternatives to assigned homework and readings if the textbook is not accessible. These commenters remarked that educational institutions should report to students whether a textbook is accessible or not when the course is advertised, since this materially impacts the likelihood of timely access to the textbook. Commenters said that advertising this information about the accessibility status of a textbook also helps make the faculty members more aware for future decision making.

Response: The Department appreciates these comments and also recognizes the importance of the accessibility of digital textbooks for students regardless of disability status, and notes that the majority of commenters expressed concern with the possibility of lowered standards for the accessibility of digital textbooks. After weighing all the comments, the Department believes the most prudent approach is to treat digital textbooks, including EPUBs (electronic publications), the same as all other educational course materials, which are subject to this rule's accessibility requirements. The Department believes that treating digital textbooks, including EPUBs, in any other way would lead to the same problems with respect to the proposed exceptions for password-protected class or course content. For example, if the Department created a similar exception for digital textbooks, it could result in courses being partially accessible and partially inaccessible for certain time periods while books are remediated to meet the needs of an individual with a disability, which could be confusing for both educational institutions and students with disabilities. Furthermore, it would be virtually impossible to set forth a remediation timeframe that would provide educational institutions sufficient time to make digital textbooks accessible without putting students with disabilities too far behind their peers. Accordingly, the Department did not make any changes to the rule to specifically address digital textbooks. The Department notes that if there are circumstances where certain aspects of digital textbooks cannot conform to WCAG 2.1 Level AA without changing the meaning of the content, recipients may assess whether the fundamental alteration or undue financial or administrative burdens limitations apply, as provided in § 84.88. However, if an action required to comply with § 84.88 would result in such an alteration or such burdens, a recipient must take any other action that would not result in such an alteration or such

burdens but would nevertheless ensure that, to the maximum extent possible, individuals with disabilities receive the benefits or services provided by the recipient.

The Department also recognizes that WCAG 2.2 is a newer standard but, as discussed, the Department is adopting WCAG 2.1 Level AA to balance benefits for individuals with disabilities with feasibility for recipients making their content accessible in compliance with this rule. In addition, the Department believes that digital textbooks should be subject to the same standards as other web content and mobile apps to reduce confusion and ensure a uniform experience and expectations for users with disabilities.

The Department also recognizes the importance of the accessibility of digital books for students regardless of disability status, and notes that the majority of commenters expressed concern with the possibility of lowered standards for the accessibility of digital books. The Department agrees that third-party publishers will play an important role in making digital books accessible and appreciates the concerns expressed by commenters that educational institutions may have limited power to require third-party vendors to make content accessible. The Department believes that the delayed compliance dates in this rulemaking will help recipients establish contracts with third-party vendors with sufficient lead time to enable the production of materials that are accessible upon being created. In addition, if this rulemaking incentivizes publishers to produce accessible content, that decision may enable hundreds of educational institutions subject to this rule to obtain accessible content. The Department also expects that as a result of this rulemaking, there will be an increase in demand for accessible content from third-party vendors, and therefore a likely increase in the number of third-party vendors that are equipped to provide accessible content.

The Department also appreciates the suggestion of requiring an advertisement of whether a course's digital books are accessible, but believes that a more appropriate solution, based mainly on the overwhelming support for accessible digital books, would simply be to require all such content to be accessible.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, the Department has decided not to include proposed § 84.85(e) in the final rule.

Proposed § 84.85(f) contained an exception for password-protected class or course content used by elementary and secondary schools with limitations based on when the recipient knew or should have known that a student is preregistered for a course or has enrolled in a course after the start of the academic term, and the student or their parent will be unable to access the password-protected class or course content due to disability. The Department invited comment on the following questions pertaining to elementary and secondary schools:

- *Web Accessibility Question 38: How difficult would it be for elementary and secondary schools to comply with this rule in the absence of this exception?*
- *Web Accessibility Question 39: What would the impact of this exception be on people with disabilities?*
- *Web Accessibility Question 40: How do elementary and secondary schools communicate general information and class- or course-specific information to students and parents?*
- *Web Accessibility Question 41: The proposed exception and its limitations are confined to content on a password-protected or otherwise secured website for students enrolled, or parents of students enrolled, in a specific class or course. Do elementary or secondary schools combine and make available content for all students in a particular grade or certain classes (e.g., all 10th graders in a school taking chemistry in the same semester) using a single password-protected website and, if so, should such content be included in the exception?*
- *Web Accessibility Question 42: Do elementary and secondary schools have a system allowing a parent with a disability to provide notice of their need for accessible course content?*
- *Web Accessibility Question 43: On average, how much content and what type of content do password-protected course websites of elementary or secondary schools contain? Is there content posted by students or parents? Should content posted by students or parents be required to be accessible and, if so, how long would it take an elementary or secondary school to make it accessible?*
- *Web Accessibility Question 44: How long would it take to make class- or course content available on a recipient's password-protected or otherwise secured website for the particular class or course accessible, and does this vary based on the type of course? Do parents and students need access to class or course content before the first day of class? How much delay in accessing online course content can a student reasonably overcome in order to have an equal opportunity to succeed in a course, and does the answer change depending on the point in the academic term that the delay occurs?*
- *Web Accessibility Question 45: To what extent do elementary or secondary schools use or offer students or parents mobile apps to enable access to password-protected course content? Should the Department apply the same exceptions and limitations to the exceptions under § 84.85(f) introductory text and (f)(1) through (4), respectively, to mobile apps?*
- *Web Accessibility Question 46: Should the Department consider an alternative approach, such as requiring that all newly posted course content be made accessible on an expedited time frame, while adopting a later compliance date for remediating existing content?*

The comments and our responses on § 84.85(f) are set forth below.

Comment: Several commenters disagreed with implementing the exception for password-protected class or course content. Commenters said that this exception conflicts with ED's recommendations to States and school districts regarding the best ways to exemplify conditions and services for creating and sustaining a Statewide, high-quality accessible, educational materials (AEM) provision system that is also designed to meet statutory requirements under the Individuals with Disabilities Education Act (IDEA) and to assure students have access to the requisite assistive technology to access AEM. Commenters said if the exception remains, virtually every student with a relevant disability would be discriminated against in violation of both Federal and State statutes.

A couple of commenters mentioned that there have been legal actions that have resulted in schools directing significant financial and human power to accessibility. Commenters stated that by not including the exception and requiring accessibility of password-protected class or course content, the burden of making materials accessible would be taken off of teachers, who are already overburdened, and instead require action and investment from schools and districts.

Some commenters urged HHS to not sanction recipients that purchase inaccessible content and platforms. Several other commenters agreed with this exception.

Response: The Department appreciates these comments and recognizes that many commenters believe this proposed exception would have a negative impact on the education of elementary and secondary students with disabilities. For all of the reasons

commenters have provided, in addition to the reasons discussed above regarding the Department's decision not to adopt § 84.85(e), the Department will not include this proposed exception in the final rule.

With respect to schools and districts redirecting funding and resources towards accessibility, the Department acknowledges that, while this rulemaking may unburden teachers from having to ensure accessibility, it would also impose costs on recipients. Full estimates of costs can be found in the accompanying RIA. While recipients will likely incur costs to comply with this final rule, the RIA indicates that in comparing annualized costs and benefits of this rule, the monetized benefits to society outweigh the costs. In addition, the Department reminds recipients that they are already required to ensure that their programs and activities, including the programs and activities of educational institutions, are accessible to people with disabilities.[173]

Comment: Several commenters stated that all technology used to deliver instruction in the classroom should be accessible to all individuals with disabilities from kiosks, websites, and applications; to third-party websites or apps used for class content; and to any form of information and communication technology, including virtual reality (VR).

Commenters mentioned that accessibility challenges were evident during the COVID–19 public health emergency, and that students and adults with disabilities experienced significant barriers to education, including not being able to access instruction because schools claimed they did not have the capacity to make inaccessible online curriculum programs and related digital materials accessible. Commenters noted that when digital devices (*e.g.,* laptops and tablets) and materials (print, digital, audio, video, etc.) were provided for remote use in K–16 settings in particular, many were not accessible or interoperable (compatible) with the assistive technology used by the student, preventing equal access and opportunity to make the same academic progress as students without disabilities.

Some commenters said that five days to remediate is often unreasonable because schools may not have control over third-party platforms, and even if the school could meet the five-day deadline, it still puts the child with a disability at a disadvantage behind their peers. Some commenters mentioned an online science experiment without audio information that required that the student connect pieces by using finger gestures. One commenter provided an example where a student with a disability was given an exemption for that activity but missed out on the learning opportunity. Another example was given of a popular online mathematics curriculum which stated that third graders will encounter more than 300 math skills over the course of 47 lessons. A student could miss two or three lessons and 15 to 30 skills in a five-day period. Another commenter mentioned a situation where a school district had to buy a $12,000 textbook in Braille. While the other students were online playing games, the student with a disability was reading a textbook and was not included in the learning. The teacher also had to spend time figuring out how to align the textbook and online learning.

Some commenters said this exception leaves parents with disabilities out of meaningful participation in their child's education and makes it difficult for teachers with disabilities to stay employed.

Commenters pointed out that Federal law requires that students exhaust all remedies under the IDEA before pursuing an ADA complaint. These commenters stated that the proposed exception would only further delay student access to course materials in a timely way.

Response: The Department appreciates these comments and acknowledges the concerns about accessibility challenges during the COVID–19 pandemic, the proposed 5-day remediation period, and concerns about parents with disabilities not being able to participate in their child's education. The education of children in elementary and secondary settings is of vital importance and the Department does not intend to limit the educational opportunities, development, and future career potential for students with disabilities. Because, in part, of the issues raised in the comments above, as well as the reasons discussed earlier, the Department will not include this proposed exception in the final rule. The Department also appreciates the comments about the burden on teachers to provide accessible content and align the content with their lesson plans. The Department believes that rulemaking in this area will encourage schools and districts to create or acquire accessible content, removing this burden from teachers and spurring vendors to improve the accessibility of their offerings. With respect to the different technologies that recipients use to provide education, the Department again notes the definitions of ''web content'' and ''mobile apps'' describe the content that is covered under this rule.

Comment: On how elementary and secondary schools communicate with students and parents, commenters listed several methods including through emails, posts on school district websites, and posts on social media websites.

Response: The Department appreciates these comments and notes that the definitions of ''web content'' and ''mobile apps'' describe the content that is covered under this rule.

Comment: Some commenters remarked that content on a password-protected website should not be a part of this exception. They stated that content could be hosted by a third party such as a textbook publisher. These commenters said that when third parties ensure their content is accessible, it reduces the work that teachers have to do as the content is grouped by type of course.

Response: The Department appreciates these comments. While section 504 applies to recipients of Departmental financial assistance, recipients will have to ensure that any web content or mobile apps they provide or make available, directly or through contractual, licensing, or other arrangements, is accessible. This approach is consistent with the existing framework under section 504.[174] Under this framework, recipients have obligations in other section 504 contexts where they choose to contract, license, or otherwise arrange with third parties to provide programs or activities.

Comment: A few commenters said that most schools do not have a system for parents to notify the school of a need for access and that most do not provide access to their course content. Another commenter recommended that the Department require schools to inquire with parents about accessibility needs for both them and their students during the registration process. One commenter mentioned that special education services for students are not meant for parents with disabilities and that teachers and staff are usually the ones adapting materials for students.

Response: The Department appreciates these comments. In part because of issues with parents and students requesting accessible web content and mobile apps and elementary and secondary institutions providing that accessible web content and mobile apps, the Department does

[173] *See* 45 CFR 84.4, redesignated as § 84.68.

[174] *See* 45 CFR 84.4(b)(1), redesignated § 84.68(b)(1).

not intend to keep this proposed exception in the final rule.

Comment: One commenter said that password-protected course websites may merely contain supplemental information or all the information that the student needs to participate in class, and everything in-between. Another commenter listed types of documents that may be on a password-protected course website, including commercially produced curriculum, commercially produced e-books, teacher-created materials, materials purchased or otherwise obtained by the teacher from an external source, PDFs of passages from old books, and student-created materials.

Some commenters mentioned that content could be posted by third parties such as other students doing group work. One commenter said content posted by students or parents should also be required to be accessible.

One commenter suggested teaching children in 5th grade or above about how to make their own content accessible. This commenter argued that this could be a life skill that would be useful for future employment opportunities, otherwise, the school would have to remediate content posted by students.

One commenter asked the Department whether course content that can be accessed through a PIN authentication or the user's personal email login information would be considered password-protected course content under the NPRM.

Response: The Department appreciates these comments on the range of password-protected content on elementary and secondary websites. In part because of the wide range of content on password-protected course websites and its importance, the Department will not be including this exception in the final rule. Again, the Department notes that the definitions of ''web content'' and ''mobile apps'' describe the content that is covered, subject to the rule's exceptions and limitations.

Comment: Several commenters said that course content should be accessible on or before the first day of class for students and parents. One commenter mentioned that teachers sometimes require course work over the summer which means the content would need to be accessible earlier. One commenter said any delays should be minimal and offset by modifications in the meantime. Commentors pointed out that delays caused unnecessary stress and reduce learning outcomes.

One commenter stated that schools will take as long as the Department gives them to make the content accessible regardless of how long it actually takes them. The commenter stated that schools are juggling competing priorities, so if the Department makes this a priority, schools will follow.

Response: The Department understands these concerns and acknowledges there may be situations where providing remediated course content in five days would neither be possible or preferrable for the recipient, student, or parent. For the reasons already discussed, this final rule will not be adopting this exception.

Comment: Some commenters want the Department to adopt the same exceptions and limitations to the exceptions under § 84.85(f)(1) through (4) to mobile apps. Many commenters disagreed with applying the exception to mobile apps to enable access to password-protected course content for parents and students. Several commenters mentioned that a large majority of digital interfaces used by schools have associated mobile apps which need to be accessible for students and parents with disabilities and can be interoperable with assistive technology.

One commenter mentioned that students as young as kindergarten use mobile devices to access course materials, complete course work, and communicate with teachers. Another commenter said that schools even require mobile app use for course work in some instances.

Response: The Department appreciates these comments. The Department recognizes the importance and growing ubiquity of mobile apps in a variety of areas, including elementary and secondary education. For the reasons previously noted, the final rule does not include the exception previously proposed at § 84.85(e).

Comment: On whether the Department should consider an alternate approach to this exception, such as requiring all newly posted course content to be made accessible on an expedited time frame, one commenter said priority can be given to newly posted course content and existing required reading with the goal that the rest of the content come into compliance as well. Another commenter thought the Department should not extend the 2-to-3-year implementation period. Instead, the commenter said that schools should create a plan for remediation on the fastest possible timeline with the option to apply fundamental alteration and undue burdens limitations if appropriate and necessary.

One commenter mentioned that school curriculums for K–12 are often purchased on either a district or State level every three-to-five years. While such planning gives teachers less autonomy over their curriculums, by purchasing curriculums on a district or State level, accessibility concerns have drastically reduced. The same commenter recommended that institutions prioritize their proactive accessibility efforts along three dimensions: (1) classes that are required for graduation or promotion to the next grade, (2) district-level curriculum and educational technology adoption, and (3) courses that move at an accelerated pace (*e.g.,* honors, advanced placement).

Response: The Department appreciates these comments. While some commenters suggested requiring recipients to follow specific procedures to comply with this rule, the variety of proposals the Department received from commenters indicates the harm from being overly prescriptive in how educational institutions comply with the rule. The final rule provides educational institutions with the flexibility to determine how best to bring their content into compliance within the two or three years they have to begin complying with this rule.

Some commenters suggested that the Department should require all new course content to be made accessible more quickly, while providing a longer time period for recipients to remediate existing course content. There were a range of proposals from commenters about how this could be implemented. Some commenters suggested that the Department could set up a prioritization structure for existing content, requiring educational institutions to prioritize the accessibility of, for example, content for required courses; content for district-level courses; and content for honors-level courses.

The Department does not believe these approaches would be feasible. Treating new course content differently than existing course content could result in particular courses being partially accessible and partially inaccessible, which could be confusing for both educational institutions and students, and make it challenging for students with disabilities to have full and timely access to their courses. Moreover, even under this hybrid approach, the Department would presumably need to retain remediation timeframes for recipients to meet upon receiving a request to make existing course content accessible. For the reasons discussed above, it would be virtually impossible to set forth a remediation timeframe that would

provide educational institutions sufficient time to make content accessible without putting students with disabilities too far behind their peers. In addition, given the wide variation in types of courses and educational institution structures, it would be difficult to set a prioritization structure for existing content that would be workable across all such institutions.

The Department believes the better approach is to not include the course content exceptions in the final rule to avoid the need for educational institutions to make content accessible on an expedited timeframe on the back end, and to instead require recipients to treat course content like any other content covered by this rule.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, the Department has decided not to include proposed § 84.85(f) in the final rule.

Proposed § 84.85(g) contained an exception for individualized, password-protected documents. The Department invited comment on following questions regarding this exception:

- *Web Accessibility Question 47: What kinds of individualized, conventional electronic documents do recipients make available and how are they made available (e.g., on websites or mobile apps)? How difficult would it be to make such documents accessible? How do people with disabilities currently access such documents?*
- *Web Accessibility Question 48: Do recipients have an adequate system for receiving notification that an individual with a disability requires access to an individualized, password-protected conventional electronic document? What kinds of burdens do these notification systems place on individuals with disabilities and how easy are these systems to access? Should the Department consider requiring a particular system for notification or a particular process or timeline that recipients must follow when they are on notice that an individual with a disability requires access to such a document?*
- *Web Accessibility Question 49: What would the impact of this exception be on people with disabilities?*
- *Web Accessibility Question 50: Which provisions of this rule, including any exceptions (e.g., individualized, password-protected conventional electronic documents; content posted by a third party), should apply to mobile apps?*

The comments and our responses regarding § 84.85(g) are set forth below.

Comment: Commenters provided many examples of individualized, password-protected conventional electronic documents, including, but not limited to: test results, clinical summaries, post-operative care instructions, current and past bills, determination letters, patient health summaries, patient letters, questionnaires, results and reports, appointments, past visits, immunization records, explanation of benefits, receipts, diagnoses, imaging results, and treatment plans.

Some commenters supported the individualized, password-protected conventional electronic document exception. Several others wanted the exception eliminated, saying that many documents are already being made accessible in accordance with public law, such as electronic health records. These commenters also mentioned that making such documents accessible can be done without much difficulty; one commenter said that this is achievable through automated generation of accessible PDFs from HTML with layouts that are not overly complex. Many commenters pointed to the fundamental alteration and undue burdens limitations already available to recipients. Commenters believed this exception was disincentivizing recipients making content accessible.

One commenter asked the Department for guidance on how to best support providing accommodations to the public for PDF documents and whether they would need to make any workflow undertaken by a patient after authenticating such as when a patient uses a patient portal to schedule an appointment with their provider.

Response: After reviewing the comments, the Department has decided to retain this exception in the final rule. The Department continues to believe that recipients often provide or make available a large volume of individualized, password-protected or otherwise secured conventional electronic documents, many of which do not pertain to individuals with disabilities, and it may be difficult to make all such documents accessible. Therefore, the Department believes it is sensible to permit entities to focus their resources on ensuring accessibility for the specific individuals who need accessible versions of those documents. If, as many commenters suggested, it is in fact more efficient and less expensive for some recipients to make all such documents accessible by using a template, there is nothing in the rule that prevents recipients from taking that approach.

The Department notes that this exception applies only to password-protected or otherwise secured content. Content may be otherwise secured if it requires a member of the public to use some process of authentication or login to access the content. Unless subject to another exception, conventional electronic documents that are on a recipient's general, public web platform would not be covered by the exception.

The Department recognizes that there may be some overlap between the content covered by this exception and the exception for certain preexisting conventional electronic documents, § 84.85(b). The Department notes that if web content is covered by the exception for individualized, password-protected or otherwise secured conventional electronic documents, it does not need to conform to WCAG 2.1 Level AA to comply with this rule, even if the content fails to qualify for another exception, such as the preexisting conventional electronic document exception. For example, a recipient might retain on its website an individualized, password-protected unpaid medical bill in a PDF format that was posted before the date the entity was required to comply with this rule. Because the PDF would fall within the exception for individualized, password-protected or otherwise secured conventional electronic documents, the documents would not need to conform to WCAG 2.1 Level AA, regardless of how the preexisting conventional electronic documents exception might otherwise have applied.

The Department understands the concerns raised by commenters about the potential burdens that people with disabilities may face if individualized password-protected or otherwise secured documents are not all made accessible at the time they are created and about the potential negative consequences for people with disabilities who do not have timely access to the documents that pertain to them. The Department reiterates that, even when documents are covered by this exception, the existing section 504 obligations require recipients to furnish appropriate auxiliary aids and services where necessary to ensure an individual with a disability has, for example, an equal opportunity to enjoy the benefits of a service.[175] Such auxiliary aids and services could include, for example, providing PDFs that are accessible. In order for such an auxiliary aid or service to ensure effective communication, it must be provided in a timely manner, and in such a way as to protect the

[175] *See* 45 CFR 84.68(b)(1)(ii), (b)(7), 84.77.

privacy and independence of the individual with a disability. Whether a particular solution provides effective communication depends on circumstances in the interaction, including the nature, length, complexity, and context of the communication, per § 84.77(b)(2). For example, the presence of an emergency situation or a situation where information is otherwise urgently needed would impact what it would mean for a recipient to ensure it is meeting its effective communication obligations. Recipients can help to facilitate effective communication by providing individuals with disabilities with notice about how to request accessible versions of their individualized documents.

Moreover, while individualized, password-protected or otherwise secured conventional electronic documents are subject to this exception, any public-facing, web- or mobile app-based system or platform that a recipient uses to provide or make available those documents or to allow the public to make accessibility requests, must itself be accessible as defined in § 84.84 if it is not covered by another exception. The recipient would need to ensure that that platform complies with § 84.84. In addition, web content and content in mobile apps that does not take the form of individualized, password-protected or otherwise secured conventional electronic documents but instead notifies users about the existence of such documents must still conform to WCAG 2.1 Level AA unless it is covered by another exception. For example, a hospital's health records portal may include a list of links to download individualized, password-protected PDF medical records. Under WCAG 2.1 Success Criterion 2.4.4, a recipient would generally have to provide sufficient information in the text of the link alone, or in the text of the link together with the link's programmatically determined link context, so that a user could understand the purpose of each link and determine whether they want to access a given document.

The Department also reiterates that a recipient might also need to make reasonable modifications to ensure that a person with a disability has equal access to its programs or activities. For example, if a covered medical provider has a policy under which administrative support staff are in charge of uploading PDF versions of X-ray images into patients' individualized accounts after medical appointments, but the provider knows that a particular patient is blind, the provider may need to modify its policy to ensure that a staffer with the necessary expertise provides an accessible version of the information the patient needs from the X-ray. Also, at this time, the Department declines to provide guidance on PDF documents, but may provide future guidance, where appropriate.

The Department also understands that some of these documents, especially documents without complex layouts, may be made accessible relatively easily, including through automated generation. Even with the proposed exception, many recipients may decide that they will change their templates for individualized password-protected or otherwise secured conventional electronic documents to make them all accessible in order to avoid modifying individual documents after the fact for people with disabilities.

Comment: Many commenters said that the time that recipients spend on building a notification system would be better spent on making documents accessible from the start. Otherwise, commenters said that recipients generally do not provide a clear means of notification. One commenter wanted more robust requirements and enforcement. Several commenters suggested making methods of contact in easy-to-access location such as on a download index page, front page of a portal and throughout the online system in an accessible manner.

One State said it did not have ways for individuals to request access to documents on their main State web pages, but individual units and programs sometimes have an email for general questions and comments.

Commenters want HHS to establish timelines for providing accessible individualized, password-protected conventional electronic documents if this exception is implemented. Examples that commenters provided included same day for post-operative instructions and quickly for bills. One commenter recommended a maximum of five business days for remediation as delays in getting access to individualized, password-protected conventional electronic document can be inequitable or cause harm.

Several commenters mentioned that once such a request is made for an accessible individualized, password-protected conventional electronic document, then the recipient should apply that request to all documents and notices sent to the requester with a disability going forward.

Response: The Department appreciates the comments including those on notification systems and making all individualized password-protected or otherwise secured conventional electronic documents accessible from the start as well as methods of contact. The Department, however, believes it is more appropriate to give recipients flexibility in how they provide or make available individualized, password-protected or otherwise secured conventional electronic documents, so long as those recipients ensure that individuals with disabilities have timely access to the information contained in those documents in an accessible format that protects the privacy and independence of the individual with a disability.

Moreover, the Department does not believe it is workable to prescribe a set number of days under which a recipient must make these documents accessible since the content and quantity of individualized, password-protected or otherwise secured documents may vary widely, from a one-page medical bill to thousands of pages of medical records. The range of possible timeframes that commenters suggested, coupled with the comments the Department received on the remediation timeframes that were associated with the previously proposed course content exceptions, helps to illustrate the challenges associated with selecting a specific number of days for recipients to remediate content.

The Department also notes that where, for example, a recipient is on notice that an individual with a disability needs accessible versions of an individualized, password-protected PDF medical bill, that recipient is generally required to continue to provide information from that medical bill in an accessible format in the future; the recipient generally may not require the individual with a disability to make repeated requests for accessibility.

The Department reiterates that, even when documents are covered by this exception, other section 504 obligations require recipients to furnish appropriate auxiliary aids and services where necessary to ensure an individual with a disability has, for example, an equal opportunity to enjoy the benefits of a service.[176] Whether a particular solution provides effective communication depends on circumstances in the interaction, including the nature, length, complexity, and context of the communication.[177]

Comment: Several commenters said that the impact of an exception for individualized, password-protected documents on people with disabilities would be having to rely on companions

[176] 45 CFR 84.77(b)(1).

[177] 45 CFR 84.77(b)(2).

or strangers to read their documents, attempting to request accessible formats, or pursuing legal action. If the recipient posts contact information on their websites, many commenters pointed out that the onus is still on the individual with a disability to make the requests for accessible individualized, password-protected conventional electronic documents. Commenters mentioned these requests take time, and a patient with a disability who has just had surgery, for example, may not have the energy to make requests for accessible post-operative instructions. Additionally, commenters said that people with disabilities will continue to have difficulty with independence when paying their bills, receiving communications from their doctors, reviewing and using school transcripts, reading job offer letters or notices related to a contract, accessing their medical records and other personal information.

Some commenters believe that if the Department moves forward with this exception, then recipients are disincentivized from prioritizing accessibility.

Response: While the Department agrees that people with disabilities will sometimes need access to password-protected or otherwise secured conventional electronic documents on a rapid timeline, particularly when they have important health implications, the Department disagrees that this proposed exception signals to recipients that the Department is disincentivizing accessibility. Recipients are still required to ensure that they provide accessible versions of documents to people with disabilities who request them.

As discussed, the Department believes that recipients often provide or make available a large volume of individualized, password-protected or otherwise secured conventional electronic documents, many of which do not pertain to individuals with disabilities, and it may be difficult to make all such documents accessible. Therefore, the Department believes it is sensible to permit recipients to focus their resources on ensuring accessibility for the specific individuals who need accessible versions of those documents.

The Department intends to strike the appropriate balance between accessibility and for people with disabilities and practicality for recipients.

Comment: On whether any of the exceptions discussed should apply to mobile apps, several commenters said that they believe the Department should adopt the same rules for web content and mobile apps since many people use mobile phones almost exclusively.

Response: The Department agrees that the exceptions should apply to both web content and mobile apps to the extent both web content and mobile apps are used in the contexts covered by the exceptions.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.85(g) (redesignated as § 84.85(d) due to deletions of preceding paragraphs) with the addition of ''or otherwise secured conventional electronic'' to the heading of the exception, for consistency with the text of the exception itself. This modification does not change the meaning or substance of the exception as proposed in the NPRM.

Conforming Alternate Versions (§ 84.86)

Proposed § 84.86 stated that recipients may use conforming alternate versions of web content instead of making their web content accessible only if it is not possible to make their web content directly accessible due to technical or legal limitations.

The Department invited comment on the following:

- *Web Accessibility Question 51: Would allowing conforming alternate versions due to technical or legal limitations result in individuals with disabilities receiving unequal access to a recipients' programs and activities?*

The comments and our responses regarding § 84.86 are set forth below.

Comment: Many commenters agreed that conforming alternate versions of web content should only be allowed in instances where it is impossible to make the web content in question compliant with WCAG 2.1 Level AA due to technical or legal limitations. They argued that requiring a separate website or alternative method for people with disabilities is inherently unequal and recipients should avoid such situations unless absolutely necessary. They also noted that historically, separate websites for people with disabilities have not provided the same access and functionality. Some commenters stated that recipients should be allowed to create conforming alternate version of web content regardless of technical or legal limitations because it provides more flexibility for recipients. Some of those commenters argued that WCAG 2.1 allows for conforming alternate versions and stated a belief that a separate website would allow for greater attention to detail and operability for people with disabilities.

Response: We appreciate the comments regarding the Department's approach to ''conforming alternate versions.'' Under WCAG, a ''conforming alternate version'' is a separate web page that, among other things, is accessible, up-to-date, contains the same information and functionality as the inaccessible web page, and can be reached via a conforming page or an accessibility-supported mechanism.[178] Conforming alternate versions are allowable under WCAG. For reasons explained below, the Department believes it is important to put guardrails on when recipients may use conforming alternate versions under this rule. This final rule, therefore, specifies that the use of conforming alternate versions is permitted only in limited, defined circumstances, which represents a slight departure from WCAG 2.1. Section 84.86 states that a recipient may use conforming alternate versions of web content to comply with § 84.84 only where it is not possible to make web content directly accessible due to technical or legal limitations.

Generally, to conform to WCAG 2.1, a web page must be directly accessible in that it satisfies the success criteria for one of the defined levels of conformance—in the case of this final rule, Level AA.[179] However, as noted above, WCAG 2.1 also allows for the creation of a ''conforming alternate version.'' The purpose of a ''conforming alternate version'' is to provide individuals with relevant disabilities access to the information and functionality provided to individuals without relevant disabilities, albeit via a separate vehicle. The Department believes that having direct access to accessible web content provides the best user experience for many individuals with disabilities, and it may be difficult to reliably maintain conforming alternate versions, which must be kept up to date. W3C explains that providing a conforming alternate version is intended to be a ''fallback option for conformance to WCAG and the preferred method of conformance is to make all content directly accessible.'' [180] However, WCAG 2.1 does not explicitly limit the circumstances under which a

[178] *See* W3C, *Web Content Accessibility Guidelines 2.1, Conforming Alternate Version* (June 5, 2018), *https://www.w3.org/TR/WCAG21/#dfn-conforming-alternate-version* [*https://perma.cc/5NJ6-UZPV*].

[179] *See* W3C, *Web Content Accessibility Guidelines 2.1* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F*.

[180] *See* W3C, *Understanding Conformance* (last updated June 20, 2023), *https://www.w3.org/WAI/WCAG21/Understanding/conformance* [*https://perma.cc/QSG6-QCBL*].

recipient may choose to create a conforming alternate version of a web page instead of making the web page directly accessible.

The Department is concerned that WCAG 2.1 can be interpreted to permit the development of two separate versions of a recipient's web content—one for individuals with relevant disabilities and another for individuals without relevant disabilities—even when doing so is unnecessary and when users with disabilities would have a better experience using the main web content that is accessible. Such an approach would result in segregated access for individuals with disabilities and be inconsistent with how section 504's core principles of inclusion and integration have been historically interpreted.[181] The Department is also concerned that the frequent or unbounded creation of separate web content for individuals with disabilities may, in practice, result in unequal access to information and functionality. For example, and as discussed later in this section, the Department is concerned that an inaccessible conforming alternate version may provide information that is outdated or conflicting due to the maintenance burden of keeping the information updated and consistent with the main web content. As another example, use of a conforming alternate version may provide a fragmented, separate, or less interactive experience for people with disabilities because recipients may assume that interactive features are not financially worthwhile or otherwise necessary to incorporate in conforming alternate versions. Ultimately, as discussed later in this section, the Department believes there are particular risks associated with permitting the creation of conforming alternate versions where not necessitated by the presence of technical or legal limitations.

Due to the concerns about user experience, segregation of users with disabilities, unequal access to information, and maintenance burdens discussed above, the Department is adopting a slightly different approach to conforming alternate versions than that provided under WCAG 2.1. Instead of permitting recipient to adopt conforming alternate versions whenever they believe it is appropriate, § 84.86 states that a recipient may use conforming alternate versions of web content to comply with § 84.84 only where it is not possible to make web content directly accessible due to technical limitations (*e.g.,* technology is not yet capable of being made accessible) or legal limitations (*e.g.,* web content that cannot be changed due to legal reasons). The Department believes conforming alternate versions should be used rarely—when it is truly not possible to make the content accessible for reasons beyond the recipient's control. However, § 84.86 does not prohibit recipients from providing alternate versions of web pages *in addition* to their WCAG 2.1 Level AA compliant main web page to possibly provide users with certain types of disabilities a better experience.

Having reviewed public comments and considered this issue carefully, the Department believes the rule strikes the right balance to permit conforming alternate versions, but only where it is not possible to make web content directly accessible due to technical or legal limitations. The Department believes that this approach ensures that generally, people with disabilities will have direct access to the same web content that is accessed by people without disabilities, but it also preserves flexibility for recipients in situations where, due to a technical or legal limitation, it is impossible to make web content directly accessible. The Department also believes that this approach will help avoid the concerns noted above with respect to segregation of people with disabilities by defining only specific scenarios when the use of conforming alternate versions is appropriate.

The determination of when conforming alternate versions are needed or permitted varies depending on the facts. For example, a conforming alternate version would not be permissible just because a recipient's web developer lacked the knowledge or training needed to make content accessible; that would not be a technical limitation within the meaning of § 84.86. By contrast, the recipient could use a conforming alternate version if its web content included a new type of technology that it is not yet possible to make accessible, such as a specific kind of immersive virtual reality environment. Similarly, a recipient would not be permitted to claim a legal limitation because its general counsel failed to approve contracts for a web developer with accessibility experience. Instead, a legal limitation would apply when the inaccessible content itself could not be modified for legal reasons specific to that content. The Department believes this approach is appropriate because it ensures that, whenever possible, people with disabilities have access to the same web content that is available to people without disabilities.

The Department would also like to clarify the interaction between the allowance of conforming alternate versions under § 84.86 and the general limitations provided in § 84.88. These two provisions are applicable in separate circumstances. If there is a technical or legal limitation that prevents a recipient from complying with § 84.84 for certain content, § 84.86 is applicable. The recipient can create a conforming alternate version for that content, and, under § 84.86, that recipient will be in compliance with this final rule. Separately, if a fundamental alteration or undue financial and administrative burdens prevent a recipient from complying with § 84.84 for certain content, § 84.88 is applicable. As set forth in § 84.88, the recipient must still ''take any other action that would not result in such an alteration or such burdens but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient to the maximum extent possible.'' A recipient's legitimate claim of fundamental alteration or undue burdens does not constitute a legal limitation under § 84.86 for which a conforming alternate version automatically suffices to comply with the rule. Rather, the recipient must ensure access ''to the maximum extent possible'' under the specific facts and circumstances of the situation. Under the specific facts a recipient is facing, the recipient's best option to ensure maximum access may be an alternate version of its content, but the recipient also may be required to do something more or something different. Because the language of § 84.88 already allows for alternate versions if appropriate for the facts of recipient's fundamental alteration or undue burdens, the Department does not see a need to expand the language of § 84.86 to address commenters' concerns.

The Department also wishes to clarify the relationship between §§ 84.86 and 84.89, which are analyzed independently of each other. Section 84.86 provides that a recipient may use conforming alternate versions of web content, as defined by WCAG 2.1, to comply with § 84.84 *only* where it is not possible to make web content directly accessible due to technical or legal limitations. Accordingly, if a recipient does not make its web content directly accessible and instead provides a conforming alternate version when not required by technical or legal limitations, the recipient may not use that conforming alternate version to

[181] Redesignated, with minor revisions, at 45 CFR 84.68(d).

comply with its obligations under the rule, either by relying on § 84.86 or by invoking § 84.89.

Summary of Regulatory Changes

The Department will make a slight edit to § 84.86 to replace ''websites and web content'' with ''web content.'' Upon further review, the Department determined that ''web content'' is more in line with the rest of the rule and would limit potential confusion among sections, including § 84.84. This change will not alter the meaning of § 84.86.

Equivalent Facilitation (§ 84.87)

Proposed § 84.87 stated that recipients may use alternative methods to those described in this subpart when the alternative method results in substantially equivalent or greater accessibility and usability of the web content or mobile app.

Section 84.87 provides that nothing prevents a recipient from using designs, methods, or techniques as alternatives to those prescribed in the regulation, provided that such alternatives result in substantially equivalent or greater accessibility and usability. The 1991 and 2010 ADA Standards for Accessible Design both contain an equivalent facilitation provision.[182] The reason for allowing for equivalent facilitation in this subpart is to encourage flexibility and innovation by recipients while still ensuring equal or greater access to web content and mobile apps. Especially in light of the rapid pace at which technology changes, this provision is intended to clarify that recipients can use methods or techniques that provide equal or greater accessibility than this rule would require. For example, if a recipient wanted to conform its web content or mobile app to a future web and mobile app accessibility standard that expands accessibility requirements beyond WCAG 2.1 Level AA, this provision makes clear that the recipient would be in compliance with this rule. Recipients could also choose to comply with this rule by conforming their web content to WCAG 2.2 Level AA [183] because WCAG 2.2 Level AA provides substantially equivalent or greater accessibility and usability to WCAG 2.1 Level AA; in particular, WCAG 2.2 Level AA includes additional success criteria not found in WCAG 2.1 Level AA and every success criterion in WCAG 2.1 Level AA, with the exception of one success criterion that is obsolete.[184]

Similarly, a recipient could comply with this rule by conforming its web content and mobile apps to WCAG 2.1 Level AAA,[185] which is the same version of WCAG and includes all the WCAG 2.1 Level AA requirements, but includes additional requirements not found in WCAG 2.1 Level AA for even greater accessibility. For example, WCAG 2.1 Level AAA includes Success Criterion 2.4.10 [186] for section headings used to organize content and Success Criterion 3.1.4 [187] that includes a mechanism for identifying the expanded form or meaning of abbreviations, among others. The Department believes that this provision offers needed flexibility for recipients to provide usability and accessibility that meet or exceed what this rule would require as technology continues to develop. The responsibility for demonstrating equivalent facilitation rests with the recipient.

Summary of Regulatory Changes

The Department is finalizing § 84.87 as proposed with a single minor modification to add a missing comma.

Duties (§ 84.88)

Proposed § 84.88 stated that if compliance with § 84.84 would result in a fundamental alteration in the nature of a program or activity or undue financial and administrative burdens, the recipient is only required to comply with § 84.84 to the extent it does not result in a fundamental alteration or undue financial and administrative burdens. It also stated that a recipient has the burden of proving that compliance with § 84.84 would result in such alteration or burdens, and the decision that compliance would result in such alteration or burdens must be made by the head of a recipient or their designee after considering all resources available for use in the funding and operation of the program or activity, and must be accompanied by a written statement of the reasons for reaching that conclusion. In addition, it stated that a recipient shall take any other action that would not result in such an alteration or such burdens but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient to the maximum extent possible.

The comments and our responses regarding § 84.88 are set forth below.

Comment: Many commenters expressed appreciation for proposed § 84.88 and opposed any measures that would constitute a fundamental alteration or undue burden. Some commenters asked for additional guidance on what would constitute a fundamental alteration or undue burden.

Response: The Department appreciates these comments. In determining whether an action would result in undue financial and administrative burdens, all of a recipient's resources available for use in the funding and operation of the program or activity should be considered. The burden of proving that compliance with the requirements of § 84.84 would fundamentally alter the nature of program or activity, or would result in undue financial and administrative burdens, rests with the recipient. These limitations on a recipient's duty to comply with the regulatory provisions mirror the fundamental alteration and undue burdens compliance limitations under the ADA title II regulation,[188] and are consistent with how the limitations already operate in many contexts under section 504. These limitations are thus familiar to many recipients.

The Department believes, in general, it would not constitute a fundamental alteration of a recipient's programs or activities to modify web content or mobile apps to make them accessible within the meaning of this final rule. However, this is a fact-specific inquiry, and the Department provides some examples later in this section of when a recipient may be able to claim a fundamental alteration. Moreover, like the fundamental alteration or undue burdens limitations in the title II regulation and elsewhere in this final rule, § 84.88 does not relieve a recipient of all obligations to individuals with disabilities. Although a recipient under this rule is not required to take actions that would result in a fundamental

[182] *See* 28 CFR part 36, appendix D at 1000 (1991); 36 CFR part 1191, appendix B at 329.

[183] W3C, *WCAG 2 Overview, https://www.w3.org/WAI/standards-guidelines/wcag/* [*https://perma.cc/RQS2-P7JC*] (Oct. 5, 2023).

[184] W3C, *What's New in WCAG 2.2 Draft, https://www.w3.org/WAI/standards-guidelines/wcag/new-in-22/* [*https://perma.cc/GDM3-A6SE*] (Oct. 5, 2023).

[185] W3C, *Web Content Accessibility Guidelines (WCAG) 2.1,* § *5.2 Conformance Requirements* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/#conformance-reqs* [*https://perma.cc/XV2E-ESM8*].

[186] *See* W3C, *Web Content Accessibility Guidelines (WCAG) 2.1, Success Criterion 2.4.10 Section Headings* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/#conformance-reqs:~:text=Success%20Criterion%202.4.10,Criterion%204.1.2* [*https://perma.cc/9BNS-8LWK*].

[187] *See* W3C, *Web Content Accessibility Guidelines (WCAG) 2.1, Success Criterion 3.1.4 Abbreviations* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/#conformance-reqs:~:text=Success%20Criterion%203.1.4,abbreviations%20is%20available* [*https://perma.cc/ZK6C-9RHD*].

[188] *See* 28 CFR 35.150(a)(3), 35.164, 35.130(b)(7).

alteration in the nature of a program or activity, or in undue financial and administrative burdens, it nevertheless must comply with the requirements of this subpart to the extent that compliance does not result in a fundamental alteration or undue financial and administrative burdens. For instance, a recipient might determine that complying with all of the success criteria under WCAG 2.1 Level AA would result in a fundamental alteration or undue financial and administrative burdens. However, the recipient must then determine whether it can take any other action that would not result in such an alteration or such burdens, but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient to the maximum extent possible. To the extent that the recipient can, it must do so. This may include the recipient bringing its web content into conformance to some of the WCAG 2.1 Level A or Level AA success criteria.

Whether the undue burdens limitation applies is a fact-specific assessment that involves considering a variety of factors. For example, some recipients have minimal operating budgets measured in the thousands or tens of thousands of dollars. If such a recipient had an archive section of its website with a large volume of older and historical material (such as old photographs), the recipient would have an obligation under the existing section 504 regulation to ensure that its programs and activities offered using web content and mobile apps are accessible to individuals with disabilities. However, it might be an undue burden for the recipient to make all those materials fully accessible in a short period of time in response to a request by an individual with a disability.[189] Whether the undue burdens limitation applies, however, would depend, among other things, on how large the recipient's operating budget is and how much it would cost to make the materials in question accessible. Whether the limitation applies will also vary over time. Increases in the recipient's budget, or changes in technology that reduce the cost of making the historical materials accessible, may make the limitation inapplicable. Lastly, even where it would impose an undue burden on the recipient to make its historical materials accessible within a certain time frame, the recipient would still need to take any other action that would not result in such a burden but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient to the maximum extent possible.

Application of the fundamental alteration limitation is similarly fact specific. For example, a recipient might hold an art contest in which students submit alternative covers for their favorite books and students view and vote on the submissions on the recipient's website. It would likely be a fundamental alteration to require the recipient to modify each piece of artwork so that any text drawn on the alternative covers, such as the title of the book or the author's name, satisfies the color contrast requirements in the technical standard. Even so, the recipient would still be required to take any other action that would not result in such an alteration but would nevertheless ensure that individuals with disabilities could participate in the contest to the maximum extent possible.

Because each assessment of whether the fundamental alteration or undue burdens limitations applies will vary depending on the recipient, the time of the assessment, and various other facts and circumstances, the Department declines to adopt any rebuttable presumptions about when the fundamental alteration or undue burdens limitations would apply.

Complying with the web and mobile app accessibility requirements set forth in §§ 84.84 to 84.89 means that a recipient of Federal financial assistance from the Department is not required by this section 504 rule to make any further modifications to the web content or content in mobile apps that it makes available to the public. However, it is important to note that compliance with §§ 84.84 through 84.89 will not relieve recipients of their distinct employment-related obligations under section 504, which applies the employment standards set forth in title I of the ADA, as described in § 84.16. The Department realizes that this rule is not going to meet the needs of and provide access to every individual with a disability, but believes that setting a consistent and enforceable web accessibility standard that meets the needs of a majority of individuals with disabilities will provide greater predictability for recipients, as well as added assurance of accessibility for individuals with disabilities.

This approach is consistent with the approach that the Department of Justice has taken in the context of physical accessibility under title II. In that context, a covered entity is not required to exceed the applicable design requirements of the ADA Standards even if certain wheelchairs or other power-driven mobility devices require a greater degree of accessibility than the ADA Standards provide.[190] The entity may still be required, however, to make other modifications to how it provides a program, service, or activity, where necessary to provide access for a specific individual. For example, where an individual with a disability cannot physically access a program provided in a building that complies with the ADA Standards, the covered entity does not need to make physical alterations to the building but may need to take other steps to ensure that the individual has an equal opportunity to participate in and benefit from that program.

Similarly, just because a recipient is in compliance with this rule's web content or mobile app accessibility standard does not mean it has met all of its obligations under section 504 or other applicable laws—it means only that it is not required to make further changes to the web content or content in mobile apps that it makes available. If an individual with a disability, on the basis of disability, cannot access or does not have equal access to a program or activity through a recipient's web content or mobile app that conforms to WCAG 2.1 Level AA, the recipient is still obligated under § 84.84(a) to provide the individual an alternative method of access to that program or activity unless the recipient can demonstrate that alternative methods of access would result in a fundamental alteration in the nature of a program or activity or in undue financial and administrative burdens. The recipient also must still satisfy its general obligations to provide effective communication, reasonable modifications, and an equal opportunity to participate in or benefit from the recipient's programs or activities.

The recipient must determine on a case-by-case basis how best to meet the needs of those individuals who cannot access a program or activity that the recipient provides through web content or mobile apps that comply with all of the requirements under WCAG 2.1 Level AA. A recipient should refer to 45 CFR 84.68(b)(1)(ii) to determine its obligations to provide individuals with disabilities an equal opportunity to participate in and enjoy the benefits of the recipient's programs or activities. A recipient should refer to § 84.77 (effective communication) to determine its obligations to provide individuals with disabilities with the appropriate auxiliary aids and services necessary to afford them an equal opportunity to

[189] *See* proposed 45 CFR 84.68(b)(1)(ii), (b)(7), 84.77, 84.81.

[190] *See* 28 CFR part 35, appendix A at 626 (2022).

participate in, and enjoy the benefits of, the recipient's programs or activities. A recipient should refer to § 84.68(b)(7) (reasonable modifications) to determine its obligations to provide reasonable modifications in policies, practices, or procedures to avoid discrimination on the basis of disability. It is helpful to provide individuals with disabilities with information about how to obtain the modifications or auxiliary aids and services they may need. For example, while not required in this final rule, a recipient is encouraged to provide an email address, accessible link, accessible web page, or other accessible means of contacting the recipient to provide information about issues individuals with disabilities may encounter accessing web content or mobile apps or to request assistance. Providing this information will help recipients to ensure that they are satisfying their obligations to provide equal access, effective communication, and reasonable modifications.

The Department also clarifies that a recipient's requirement to comply with general equal access, effective communication, and reasonable modification obligations remains in place for content that fits under one of the exceptions under § 84.85. For example, in the appropriate circumstances, a recipient may be obligated to add captions to a video that falls within the archived content exception and provide the captioned video file to the individual with a disability who needs access to the video, or edit an individualized password-protected PDF to be usable with a screen reader and provide it via a secure method to the individual with a disability. Of course, a recipient may also choose to further modify the web content or content in mobile apps it makes available to make that content more accessible or usable than §§ 84.84 to 84.89 require. In the context of the above examples, for instance, the Department believes it will often be most economical and logical for a recipient to post the captioned video, once modified, as part of web content made available to the public; or to modify the individualized PDF template so that it is used for all members of the public going forward.

Summary of Regulatory Changes

The Department's final rule removes the word ''full'' in § 84.88 so that the text reads ''compliance'' rather than ''full compliance.'' The Department made this change because § 84.84(b)(1) and (2) clarify that compliance with this final rule includes complying with the success criteria and conformance requirements under Level A and Level AA specified in WCAG 2.1. This minor revision does not affect the meaning of § 84.88, but rather removes an extraneous word to avoid redundancy and confusion.

Measuring Compliance

In the NPRM, the Department considered four possible approaches to defining and measuring compliance, which involved linking noncompliance with a technical standard to: (a) a numerical percentage; (b) situations that impact the ability to have equal access to the website or mobile app; (c) the use of robust policies and practices for accessibility feedback, testing, and remediation; or (d) organizational maturity.[191] The Department also invited comment on the following questions regarding measuring compliance:

- *Web Accessibility Question 52: What should be considered sufficient evidence to support an allegation of noncompliance with a technical standard for purposes of enforcement action? For example, if a website or mobile app is noncompliant according to one testing methodology, or using one configuration of assistive technology, hardware, and software, is that sufficient?*
- *Web Accessibility Question 53: In evaluating compliance, do you think a recipient's policies and practices related to web and mobile app accessibility (e.g., accessibility feedback, testing, remediation) should be considered and, if so, how?*
- *Web Accessibility Question 54: If you think a recipient's policies and practices for receiving feedback on web and mobile app accessibility should be considered in assessing compliance, what specific policies and practices for feedback would be effective? What specific testing policies and practices would be effective? What specific testing policies and practices would be effective?*
- *Web Accessibility Question 55: Should a recipient be considered in compliance with this part if the recipient remediates web and mobile app accessibility errors within a certain period of time after the recipient learns of nonconformance through accessibility testing or feedback? If so, what time frame for remediation is reasonable?*
- *Web Accessibility Question 56: Should compliance with this rule be assessed differently for web content that existed on the recipient's website on the compliance date than for web content that is added after the compliance date?*
- *Web Accessibility Question 57: In evaluating compliance, do you think a recipient's organizational maturity related to web and mobile app accessibility should be considered and, if so, how? For example, what categories of accessibility should be measured? Would such an approach be useful for recipients?*
- *Web Accessibility Question 58: Should the Department consider limiting recipients' compliance obligations if nonconformance with a technical standard does not prevent a person with disabilities from accessing the programs and activities offered on the recipient's website or mobile app?*
- *Web Accessibility Question 59: When assessing compliance, should all instances of nonconformance be treated equally? Should nonconformance with certain WCAG 2.1 success criteria, or nonconformance in more frequently accessed content or more important core content, be given more weight when determining whether a website or mobile app meets a particular threshold for compliance?*
- *Web Accessibility Question 60: How should the Department address isolated or temporary noncompliance*[192] *with a technical standard and under what circumstances should noncompliance be considered isolated or temporary? How should the Department address noncompliance that is a result of technical difficulties, maintenance, updates, or repairs?*
- *Web Accessibility Question 61: Are there any local, State, Federal, international, or other laws or policies that provide a framework for measuring, evaluating, defining, or demonstrating compliance with web or mobile app accessibility requirements that the Department should consider adopting?*

The provision at § 84.89, adopted in the final rule and discussed in the summary of regulatory changes, adopts approach (b), ''situations that impact the ability to have equal access to the website or mobile app,'' from the NPRM, with a few changes.

Comment: Many commenters provided their opinions on what will be necessary to measure compliance with the proposed standard adopted in § 84.84. Almost all commenters recognized that it would be nearly impossible for recipients to conform to WCAG 2.1 Level AA across 100% of web content and mobile apps, and recognized that there must be a more nuanced method for measuring compliance. Most commenters also

[191] 88 FR 63392, 63447–49 (Sept. 14, 2023).

[192] *See* 28 CFR 35.133(b).

supported a consistent standard that could be applied across the range of recipients. One commenter stated that because the Department intends to apply a nuanced approach to measuring compliance, any of these methods for measuring compliance will be too difficult to enforce and, therefore, the Department should not adopt any of the proposed approaches to measuring compliance with the requirements of § 84.84.

Response: The Department agrees that any method for measuring compliance must be consistently applied across all recipients. The Department is also persuaded that requiring 100 percent conformance to WCAG 2.1 Level AA would not be the most prudent approach, and that a recipient's compliance obligations can be limited under some narrow circumstances without undermining the rule's objective of ensuring equal access to web content and mobile apps. The Department believes its approach should emphasize actual access, be consistent with existing legal frameworks, and is supported by a wide range of commenters.

First, digital content changes much more frequently than physical buildings—another area covered by set accessibility standards—do. Every modification to web content or a mobile app could lead to some risk of falling out of perfect conformance to WCAG 2.1 Level AA. Recipients will need to address this risk much more frequently under this subpart than they do under physical access requirements, because web content and mobile apps are updated much more often than buildings are. By their very nature, web content and mobile apps can easily be updated often, while most buildings are designed to last for years, if not decades, without extensive updates.

As such, recipients trying to comply with their obligations under this rule will need to evaluate their compliance more frequently than they evaluate the accessibility of their buildings. But regular consideration of how any change that they make to their web content or mobile app will affect conformance to WCAG 2.1 Level AA and the resulting iterative updates may still allow minor nonconformances to escape notice. Given these realities attending web content and mobile apps the Department believes that it is likely to be more difficult for recipients to maintain perfect conformance to the technical standard set forth in this rule than it is to comply with physical access standards. Commenters agreed that maintaining perfect conformance to the technical standard would be difficult.

Web content and content in mobile apps are also more likely to be interconnected, such that updates to some content may affect the conformance of other content in unexpected ways, including in ways that may lead to technical nonconformance without affecting the user experience for individuals with disabilities. Thus, to maintain perfect conformance, it would not necessarily be sufficient for recipients to confirm the conformance of their new content; they would also need to ensure that any updates do not affect the conformance of existing content. The same kind of challenge is unlikely to occur in physical spaces.

Second, some commenters raised concerns about the litigation risk that requiring perfect conformance to WCAG 2.1 Level AA would pose. Commenters feared being subjected to a flood of legal claims based on any failure to conform to the technical standard, however minor, and regardless of the impact—or lack thereof—the nonconformance has on accessibility. Commenters agreed with the Department's suggestion that due to the dynamic, complex, and interconnected nature of web content and mobile apps, a recipient's web content and mobile apps may be more likely to be out of conformance to WCAG 2.1 Level AA than its buildings are to be out of compliance with the ADA Standards, leading to increased legal risk. Some commenters even stated that 100 percent conformance to WCAG 2.1 Level AA would be unattainable or impossible to maintain. Commenters also agreed with the Department's understanding that the prevalence of automated web accessibility testing could enable any individual to find evidence of nonconformance to WCAG 2.1 Level AA even where that individual has not experienced any impact on access and the nonconformance would not affect others' access, with the result that identifying instances of merely technical nonconformance to WCAG 2.1 Level AA is likely much easier than identifying merely technical noncompliance with the ADA Standards. Based on the comments it received, the Department believes that if it does not implement a tailored approach to compliance under this rule, the burden of litigation under this subpart could become particularly challenging for recipients, enforcement agencies, and the courts. Though many comments about litigation risk came from recipients, commenters from some disability advocacy organizations agreed that the rule should not encourage litigation about issues that do not affect a person with a disability's ability to equally use and benefit from a website or mobile app, and that liability should be limited.

The Department does not agree that allowing minor deviations from the technical standard that have minimal impact on access would be too complicated and untenable. Simply because this approach may require more steps to assess compliance than checking whether a website has satisfied 100% of the WCAG 2.1 Level AA success criteria does not mean this approach is not worthwhile or feasible. As discussed further, the Department believes that the final version of § 84.89 is tenable and will help ensure the full and equal access to which individuals with disabilities are entitled while allowing some flexibility for recipients if nonconformance with WCAG 2.1 Level AA is so minimal as to not affect use of the recipient's web content or mobile app.

Comment: Commenters advanced a variety of opinions on what is sufficient evidence of noncompliance with the proposed technical standard. Many commenters stated that any enforcement method should not solely rely on automated software used to check compliance with web content, but if automated checkers are used, any violations should be confirmed by a human being. Automated checkers may result in false positives or minor variations that do not affect access, leading to a flood of legal actions. Some commenters stated that a determination of noncompliance should only be made when there is a deviation from WCAG 2.1 Level AA and the deviation negatively impacts the ability of a person with a disability to use the web content in question. Some commenters stated that a deviation from WCAG 2.1 Level AA should only be a violation if the deviation is inherent to the web content itself, is widely prevalent, or there is no evidence of institutional development in response to the deviation. One commenter summed up their opinion by stating ''the true measure of compliance is whether a person with a disability who needs access to a service can actually access it or not.''

Response: The Department agrees that the method for measuring compliance must take into consideration whether the deviation from the WCAG 2.1 Level AA success criteria impacts an individual with a disability's access to the web content in question.

Comment: Comments on whether a numerical percentage should be used to measure compliance agreed that such a

measure of compliance would be arbitrary and not ensure that people with disabilities are able to access web content. Some commenters stated that it would be difficult, if not impossible, for larger recipients to ensure 100% technical compliance at all times.

Response: The Department considered requiring a certain numerical percentage of conformance with the technical standard and declines to take this approach. The Department concluded that approach would be unlikely to ensure access. Even if only a very small percentage of content does not conform with the technical standard, that could still block an individual with a disability from accessing a program or activity. For example, even if there was only one instance of nonconformance, that single error could prevent an individual with a disability from submitting an application for benefits. As such, the Department continues to believe that a percentage-based approach would not be sufficient to advance this rule's objective to ensure equal access to recipients' web content and mobile apps.

Comment: Some commenters expressed the view that a recipient's policies and practices should be considered when determining compliance with subpart I. Some of these commenters stated that policies for receiving feedback, automated and manual testing, and remediation along a set schedule should all be taken into account. Other commenters stated that actual conformance to WCAG 2.1 Level AA, not whether a recipient has policies in place, should determine compliance, but policies could be used when determining enforcement or remediation requirements following a violation. Some commenters thought that policies should require automated testing, some thought policies should require manual testing, and still others thought policies should require both.

Response: The Department appreciates the comments on recipient policies and practices concerning web and mobile accessibility. The Department declines to adopt a policy-based approach because there is not a sufficient rationale that would justify adopting any specific set of accessibility policies in this generally applicable rule. There was no consensus among commenters about what policies would be sufficient, and most commenters did not articulate a specific basis supporting why their preferred policies were more appropriate than any other policies. In the absence of more specific rationales or a clearer consensus among commenters or experts in the field about what policies would be sufficient, the Department does not believe it is appropriate to prescribe what specific accessibility testing and remediation policies all recipients must adopt to comply with their obligations under this rule. Based on the information available to the Department at this time, the Department's adoption of any such specific policies would be unsupported by sufficient evidence that these policies will ensure accessibility, which could cause significant harm. It would allow recipients to comply with their legal obligations under this rule based on policies alone, even though those policies may fail to provide equal access to online programs or activities.

The Department also declines to adopt a policy-based approach that would rely on the type of general, flexible policies, in which the sufficiency of recipients' policies would vary depending on the factual circumstances. The Department does not believe that such an approach would give individuals with disabilities sufficient certainty about what policies and access they could expect. Such an approach would also fail to give recipients sufficient certainty about how they should meet their legal obligations under this rule. If it adopted a flexible approach, the Department might not advance the current state of the law, because every recipient could choose any accessibility testing and remediation policies it believed would be sufficient to meet its general obligations, without conforming to the technical standard or ensuring access.

The Department agrees that while it may be useful to know a recipient's policies and practices when investigating alleged violations of this subpart, the ultimate goal is accessibility as defined by the subpart. The Office for Civil Rights (OCR) is responsible for investigating allegations that recipients have violated section 504 and typically reviews recipients' policies and procedures as part of an investigation. OCR will review policies, such as policies that address feedback, testing, and timely remediation, when determining resolutions of violations or instances where recipients agree to come into voluntary compliance.

Although the final rule does not specifically require manual testing by people with disabilities, because requiring such testing could pose logistical or other hurdles, the Department recommends that recipients seek and incorporate feedback from people with disabilities on their web content and mobile apps. Doing so will help ensure that everyone has access to critical government services.

Comment: Commenters were divided on whether a recipient should be deemed to be compliant with subpart I if it remediates errors within a set time period. Some commenters stated that the compliance date for WCAG 2.1 Level AA is when the rule goes into effect for the recipient and that any question of remediation is appropriately addressed in the enforcement process. Some commenters support allowing for remediation in a set time period, ranging from three days to months. Some commenters endorsed shorter remediation time periods for recipients with multiple violations or deviations from WCAG 2.1 AA.

Response: The Department agrees that the date for recipient web content and mobile applications to comply with WCAG 2.1 Level AA is stated in the proposed rule as either two or three years after the final rule's publication date depending on the size of the recipient. However, the Department is not adopting a framework where a recipient has a certain period of time to remediate inaccessibility issues before the recipient could be considered out of compliance with the rule. The Department believes that adopting this approach would undermine a core premise of the rule, which is that web content and mobile apps will generally be accessible by default. Under section 504, individuals with disabilities cannot be, by reason of such disability, excluded from participation in or denied the benefits of recipients' programs or activities, including those offered via the web and mobile apps.[193] Accordingly, it is important for individuals with disabilities to have access to the same platforms as their neighbors and friends at the same time, and the commenters' proposal would not achieve that objective. With this rule, the Department is ensuring that people with disabilities generally will not have to request access to recipients' web content and content in mobile apps, nor will they typically need to wait to obtain that access. Given recipients' existing obligations under section 504, recipients should already be on notice of their general obligations. If they are not, this rule unquestionably puts them on notice.

Comment: Most of the commenters opposed different compliance measures for new versus preexisting content. Almost all stated that policing content based on its publication date would be too complicated and that the proposed compliance dates of two or three years are sufficient for all content.

[193] 29 U.S.C. 794(a).

Response: The Department agrees that the two- or three-year compliance periods are sufficient for recipients to make their existing web content and mobile apps accessible while preparing to make new web content and mobile apps accessible, especially given the exception for archived web content under § 84.85(a).

Comment: Most of the comments on organizational maturity as a method for measuring compliance took the position that it should not be used. Specifically, those commenters stated that there is no direct correlation between a recipient's organizational maturity and its future compliance to WCAG 2.1 AA. One commenter stated that some organizations deemed ''mature'' post inaccessible content while some organizations not deemed ''mature'' post accessible content. Some commenters voiced general support for using organizational maturity as it would be a relatively simple method for the Department to enforce. Some commenters also expressed misunderstandings concerning organizational maturity, which suggests that an organizational maturity model would be confusing to the public if adopted.

Response: There are many ways to measure organizational maturity, and it is not clear to the Department that one organizational maturity model is more appropriate or more effective than any other. The Department therefore declines to adopt an organizational maturity approach in this final rule because any organizational maturity model for compliance with web accessibility that the Department could develop or incorporate would not have sufficient justification based on the facts available to the Department at this time. As with the policy-based approach discussed above, if the Department were to allow recipients to define their own organizational maturity approach instead of adopting one specific model, this would not provide sufficient predictability or certainty for people with disabilities or recipients.

Also, like the policy-based approach discussed above, if the Department were to adopt an organizational maturity approach that was not sufficiently rigorous, recipients would be able to comply this rule without providing equal access. This would undermine the purpose of the rulemaking.

Comment: Many of the commenters agreed that the Department should limit compliance obligations if deviation from a specific WCAG 2.1 AA success criteria does not limit access of a person with a disability. Specifically, some commenters stated that a recipient should not be deemed in violation of subpart I if people with disabilities are able to access their web content and mobile apps. Some commenters stated that the Department should prioritize the usability of the web content and actual functional barriers instead of focusing only on technical violations of WCAG 2.1 Level AA. Many commenters supported a functional definition of accessibility that would effectively allow for minor deviations from the technical standard as long as they do not impact the ability of people with disabilities to access and benefit from the web content in question. Some commenters specified that the ability to access and benefit from the web content in question also requires consideration of the timeliness, privacy, and independence in accessing the web content. This method would also result in the possibility that recipients could be in violation of subpart I if any aspect of their program or activity provided through web content is inaccessible to a person with a disability, even if the recipient is fully compliant with WCAG 2.1 AA. Some commenters stated that all information posted on a recipient's web content is important so all information, regardless of whether it limits access to a recipient's program or activity, should be accessible. Some commenters oppose this method of measuring compliance because they believe it would be too difficult to enforce.

Response: The Department has considered these comments and believes a recipient should be able to meet its requirements under this rule even if the recipient's web content or mobile app does not perfectly conform to the technical standard set forth in § 84.84.

Accordingly, this final rule adopts § 84.89, which describes a particular, limited circumstance in which a recipient ''will be deemed to have met'' the requirements of § 84.84 even though the recipient's web content or mobile app does not perfectly conform to the technical standard set forth in § 84.84(b). Section 84.89 will apply if the recipient can demonstrate that, although it was technically out of conformance to WCAG 2.1 Level AA, (*i.e.,* fails to exactly satisfy a success criterion or conformance requirement), the nonconformance has a minimal impact on access for individuals with disabilities, as defined in the regulatory text. If a recipient can make this showing, it will be deemed to have met its obligations under § 84.84 despite its nonconformance to WCAG 2.1 Level AA.

Section 84.89 does not alter a recipient's general obligations under this rule, nor is it intended as a blanket justification for a recipient to avoid conforming to WCAG 2.1 Level AA from the outset. Rather, § 84.89 is intended to apply in rare circumstances and will require a detailed analysis of the specific facts surrounding the impact of each alleged instance of nonconformance. The Department does not expect or intend that § 84.89 will excuse most nonconformance to the technical standard. Under § 84.84(b), a recipient must typically ensure that the web content and mobile apps it ''provides or makes available, directly or through contractual, licensing, or other arrangements, comply with Level A and Level AA success criteria and conformance requirements specified in WCAG 2.1.'' This remains generally true. However, § 84.89 allows for some minor deviations from WCAG 2.1 Level AA if specific conditions are met. This will provide a recipient that discovers that it is out of compliance with this rule with another means to avoid the potential liability that could result. Recipients that maintain conformance to WCAG 2.1 Level AA will not have to rely on § 84.89 to be deemed compliant with this rule, and full conformance to WCAG 2.1 Level AA is the only definitive way to guarantee that outcome. However, if a recipient falls out of conformance in a minimal way or such nonconformance is alleged, a recipient may be able to use § 84.89 to demonstrate that it has satisfied its legal obligations. Section 84.89 also does not alter existing enforcement mechanisms. Individuals can file complaints, and agencies can conduct investigations and compliance reviews, related to this rule the same way they would for any other requirement under section 504.

As the text of the provision indicates, the burden of demonstrating applicability of § 84.89 is on the recipient. The provision will only apply ''in the limited circumstance in which the recipient can demonstrate'' that all of the criteria described in § 84.89 are satisfied. This section requires the recipient to show that its nonconformance to WCAG 2.1 Level AA ''has such a minimal impact on access that it would not affect the ability of individuals with disabilities to use the recipient's web content or mobile app'' to do one of the activities enumerated in paragraphs (a) through (d) of § 84.89 in the manner described in § 84.89. If the nonconformance has affected an individual in the ways outlined in § 84.89 (further described below), the recipient will not be able to rely on this

provision. Further, as ''demonstrate'' indicates, the recipient must provide evidence that all of the criteria described in § 84.89 are satisfied in order to substantiate its reliance on this provision. While § 84.89 does not require a particular type of evidence, a recipient needs to show that, as the text states, its nonconformance ''would not affect'' the experience of individuals with disabilities as outlined below. Therefore, it would not be sufficient for a recipient to show only that it has not received any complaints regarding the nonconformance; nor would it likely be enough if the recipient only pointed to a few particular individuals with disabilities who were unaffected by the nonconformance. The recipient must show that the nonconformance is of a nature that would not affect people whose disabilities are pertinent to the nonconformance at issue, just as the analysis under other parts of section 504 regulations depends on the barrier at issue and the access needs of individuals with disabilities pertinent to that barrier.[194] For example, people with hearing or auditory processing disabilities, among others, have disabilities pertinent to captioning requirements.

With respect to the particular criteria that a recipient must satisfy, § 84.89 describes both *what* people with disabilities must be able to use the recipient's web content or mobile apps to do and *the manner* in which people with disabilities must be able to do it. Nonconformance to WCAG 2.1 Level AA must not ''affect the ability of individuals with disabilities to use the recipient's web content or mobile app . . . in a manner that provides substantially equivalent timeliness, privacy, independence, and ease of use'' compared to individuals without disabilities. Timeliness, privacy, independence, and ease of use are underscored throughout the ADA framework, as well as elsewhere in this rule under section 504, as key components of ensuring equal opportunity for individuals with disabilities to participate in or benefit from a recipient's programs and activities, and ''ease of use'' is intended to broadly encompass other aspects of a user's experience with web content or mobile apps. To successfully rely on § 84.89, it would not be sufficient for a recipient to demonstrate merely that its nonconformance would not completely block people with disabilities from using web content or a mobile app as described in § 84.89(a) through (d). That is, the term ''would not affect'' should not be read in isolation from the rest of § 84.89 to suggest that a recipient only needs to show that a particular objective can be achieved. Rather, a recipient must also demonstrate that, even though the web content or mobile app does not conform to the technical standard, the user experience for individuals with disabilities is substantially equivalent to the experience of individuals without disabilities.

For example, if a recipient's online health questionnaire does not conform to WCAG 2.1 Level AA, a person with a manual dexterity disability may need to spend significantly more time to fill out a health questionnaire online than someone without a disability. This person might also need to seek assistance from someone who does not have a disability, provide personal information to someone else, or endure a much more cumbersome and frustrating process than a user without a disability. Even if this person with a disability was ultimately able to fill out the form online, § 84.89 would not apply because, under these circumstances, their ability to use the web content ''in a manner that provides substantially equivalent timeliness, privacy, independence, and ease of use'' would be affected. Analysis under this provision is likely to be a fact-intensive analysis. Of course, a recipient is not responsible for every factor that might make a task more time-consuming or difficult for a person with a disability. However, a recipient is responsible for the impact of its nonconformance to the technical standard set forth in this rule. The recipient must show that its nonconformance would not affect the ability of individuals with pertinent disabilities to use the web content or mobile app in a manner that provides substantially equivalent timeliness, privacy, independence, and ease of use.

Paragraphs (a) through (d) of § 84.89 describe what people with disabilities must be able to use the recipient's web content or mobile apps to do ''in a manner that [is] substantially equivalent [as to] timeliness, privacy, independence, and ease of use.'' First, under § 84.89(a), individuals with disabilities must be able to ''[a]ccess the same information as individuals without disabilities.'' This means that people with disabilities can access all the same information using the web content or mobile app that users without disabilities are able to access. For example, § 84.89(a) would not be satisfied if certain web content could not be accessed using a keyboard because the content was coded in a way that caused the keyboard to skip over some content. In this example, an individual who relies on a screen reader would not be able to access the same information as an individual without a disability because all of the information could not be selected with their keyboard so that it would be read aloud by their screen reader. However, § 84.89(a) might be satisfied if the color contrast ratio for some sections of text is 4.45:1 instead of 4.5:1 as required by WCAG 2.1 Success Criterion 1.4.3.[195] Similarly, this provision might apply, for example, if the spacing between English words is only 0.15 times the font size instead of 0.16 times as required by WCAG 2.1 Success Criterion 1.4.12.[196] Such slight deviations from the specified requirements are unlikely to affect the ability of, for example, most people with vision disabilities to access information that they would be able to access if the content fully conformed with the technical standard. However, the recipient must always demonstrate that this element is met with respect to the specific facts of the nonconformance at issue.

Second, § 84.89(b) states that individuals with disabilities must be able to ''[e]ngage in the same interactions as individuals without disabilities.'' This means that people with disabilities can interact with the web content or mobile app in all of the same ways that people without disabilities can. For example, § 84.89(b) would not be satisfied if people with disabilities could not interact with all of the different components of the web content or mobile app, such as chat functionality, messaging, calculators, calendars, and search functions. However, § 84.89(b) might be satisfied if the time limit for an interaction, such as a chat response, expires at exactly 20 hours, even though Success Criterion 2.2.1,[197] which generally requires certain safeguards to prevent time limits from expiring, has an exception that only applies if the time limit is longer than 20 hours. People with certain types of disabilities, such as cognitive disabilities, may need more time than people without disabilities to engage in interactions. A slight deviation in

[194] *Cf., e.g.,* 45 CFR 84.68(b)(1)(iv), (b)(8), 84.77.

[195] *See* W3C, *Web Content Accessibility Guidelines (WCAG) 2.1, Success Criterion 1.4.3 Contrast (Minimum)* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/#contrast-minimum* [*https://perma.cc/4XS3-AX7W*].

[196] *See* W3C, *Web Content Accessibility Guidelines (WCAG) 2.1, Success Criterion 1.4.12 Text Spacing* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/#text-spacing* [*https://perma.cc/B4A5-843F*].

[197] *See* W3C, *Web Content Accessibility Guidelines (WCAG) 2.1, Success Criterion 2.2.1 Timing Adjustable* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/#timing-adjustable* [*https://perma.cc/V3XZ-KJDG*].

timing, especially when the time limit is long and the intended interaction is brief, is unlikely to affect the ability of people with these types of disabilities to engage in interactions. Still, the recipient must always demonstrate that this element is met with respect to the specific facts of the nonconformance at issue.

Third, pursuant to § 84.89(c), individuals with disabilities must be able to ''[c]onduct the same transactions as individuals without disabilities.'' This means that people with disabilities can complete all of the same transactions on the web content or mobile app that people without disabilities can. For example, § 84.89(c) would not be satisfied if people with disabilities could not submit a form or process their payment. However, § 84.89(c) would likely be satisfied if web content does not conform to Success Criterion 4.1.1 about parsing. This Success Criterion requires that information is coded properly so that technology like browsers and screen readers can accurately interpret the content and, for instance, deliver that content to a user correctly so that they can complete a transaction, or avoid crashing in the middle of the transaction.[198] However, according to W3C, this Success Criterion is no longer needed to ensure accessibility because of improvements in browsers and assistive technology.[199] Thus, although conformance to this Success Criterion is required by WCAG 2.1 Level AA, a failure to conform to this Success Criterion is unlikely to affect the ability of people with disabilities to conduct transactions. However, the recipient must always demonstrate that this element is met with respect to the specific facts of the nonconformance at issue.

Fourth, § 84.89(d) requires that individuals with disabilities must be able to ''[o]therwise participate in or benefit from the same programs and activities as individuals without disabilities.'' Section 84.89(d) is intended to address anything else within the scope of section 504 (*i.e.,* any program or activity that cannot fairly be characterized as accessing information, engaging in an interaction, or conducting a transaction) for which someone who does not have a disability could use the recipient's web content or mobile app. Section 84.89(d) should be construed broadly to ensure that the ability of individuals with disabilities to access or use any part of the recipient's web content or mobile app that individuals without disabilities are able to access or use is not affected by nonconformance to the technical standard.

The Department believes this framework is generally consistent with the framework of title II of the ADA, with which many recipients will be familiar, as well as the approach reflected in the Department's revisions and additions in §§ 84.68 and 84.77 of this final rule to ensure consistency between section 504 and title II of the ADA. Title II similarly requires covered entities to provide equal opportunity to participate in or benefit from services;[200] equal opportunity to obtain the same result;[201] full and equal enjoyment of services, programs, and activities;[202] and communications with people with disabilities that are as effective as communications with others, which includes consideration of timeliness, privacy, and independence.[203]

The regulatory language codified in § 84.89 is very similar to language discussed in the NPRM's preamble.[204] However, the Department believes it is helpful to explain differences between that discussion in the NPRM and this final rule. The Department has only made three substantive changes to the NPRM's relevant language.

First, though the NPRM discussed excusing noncompliance that ''does not prevent'' equal access, § 84.89 excuses noncompliance that ''would not affect'' such access. The Department was concerned that the use of ''does not'' could have been incorrectly read to require a showing that a specific individual did not have substantially equivalent access to the web content or mobile app. In changing the language to ''would not,'' the Department clarifies that the threshold requirements for bringing a challenge to compliance under this subpart are the same as under any other provision of section 504. Except as otherwise required by existing law, a rebuttal of a recipient's invocation of this provision would not need to show that a specific individual did not have substantially equivalent access to the web content or mobile app. Rather, the issue would be whether the nonconformance is the type of barrier that would affect the ability of people with pertinent disabilities to access the web content or mobile app in a substantially equivalent manner. Certainly, the revised standard would encompass a barrier that actually does affect a specific individual's access, so this revision does not narrow the provision.

Second, the Department originally proposed considering whether nonconformance ''prevent[s] a person with a disability'' from using the web content or mobile app, but § 84.89 instead considers whether nonconformance would ''affect the ability of individuals with disabilities'' to use the web content or mobile app. This revision is intended to clarify what a recipient seeking to invoke this provision needs to demonstrate. The Department explained in the NPRM that the purpose of this approach was to ''provide equal access to people with disabilities,'' and limit violations to those that ''affect access.'' [205] But even when not entirely ''prevent[ed]'' from using web content or mobile app, an individual with disabilities can still be denied equal access by impediments falling short of that standard. The language in the final rule more accurately reflects this reality and achieves the objective proposed in the NPRM. As explained above, under the language in the final rule it would not be sufficient for a recipient to show that its nonconformance would still permit people with disabilities to use the recipient's web content or mobile app as described in § 84.89(a) through (d). In other words, someone would not need to be entirely prevented from using the web content or mobile app before a recipient could be considered out of compliance. Instead, the effect of the nonconformance must be considered. This does not mean that any effect on usability, however slight, is sufficient to prove a violation. Only nonconformance that would affect the ability of individuals with disabilities to do the activities in § 84.89(a) through (d) in a way that provides substantially equivalent timeliness, privacy, independence, and ease of use would prevent a recipient from relying on this provision.

Third, the language proposed in the NPRM considered whether a person with a disability would have substantially equivalent ''ease of use.'' The Department believed that timeliness, privacy, and independence were all components that affected

[198] W3C, *Understanding SC 4.1.1: Parsing (Level A), https://www.w3.org/WAI/WCAG21/Understanding/parsing.html* [*https://perma.cc/5Z8Q-GW5E*] (June 20, 2023).

[199] W3C, *WCAG 2 FAQ* (Oct. 5, 2023), *https://www.w3.org/WAI/standards-guidelines/wcag/faq/#parsing411* [*https://perma.cc/7Q9H-JVSZ*]. W3C, *WCAG 2 FAQ* (Oct. 5, 2023), *https://www.w3.org/WAI/standards-guidelines/wcag/faq/#parsing411* [*https://perma.cc/7Q9H-JVSZ*].

[200] 28 CFR 35.130(b)(1)(ii), 35.160(b)(1).

[201] 28 CFR 35.130(b)(1)(iii).

[202] 28 CFR 35.130(b)(8).

[203] 28 CFR 35.160.

[204] 88 FR 63392, 63447 (Sept. 14, 2023).

[205] *Id.*

whether ease of use was substantially equivalent. Because some commenters proposed explicitly specifying these factors in addition to ''ease of use,'' the Department is persuaded that these factors warrant separate inclusion and emphasis as aspects of the user experience that must be substantially equivalent. This specificity ensures clarity for recipients, individuals with disabilities, Federal agencies, and courts about how to analyze an entity's invocation of this provision. Therefore, the Department has added additional language to clarify that timeliness, privacy, and independence are all important concepts to consider when evaluating whether this provision applies. If a person with a disability would need to take significantly more time to successfully navigate web content or a mobile app that does not conform to the technical standard because of the content or app's nonconformance, that person is not being provided with a substantially equivalent experience to that of people without disabilities. Requiring a person with a disability to spend substantially more time to do something is placing an additional burden on them that is not imposed on others. Privacy and independence are also crucial components that can affect whether a person with a disability would be prevented from having a substantially equivalent experience. Adding this language to § 84.89 ensures consistency with the effective communication provision of section 504.[206] The Department has included timeliness, privacy, and independence in this provision for clarity and to avoid unintentionally narrowing what should be a fact-intensive analysis. However, ''ease of use'' may also encompass other aspects of a user's experience that are not expressly specified in the regulatory text, such as safety risks incurred by people with disabilities as a result of nonconformance.[207] ''Ease of use'' should be construed broadly to allow for consideration of other ways in which nonconformance would make the experience of users with disabilities more difficult or burdensome than the experience of users without disabilities in specific scenarios.

Regarding comments that recommended a two-part method of measuring compliance that includes a functional definition of accessibility in addition to WCAG requirements, the Department is concerned about imposing additional requirements on recipients. A major benefit of requiring conformance to WCAG 2.1 Level AA is that if a recipient's web content and mobile apps fully conform to it, the recipient can be certain that they are compliant with § 84.84. Adding a functional accessibility standard beyond WCAG would result in situations where even if a recipient is 100% in compliance with WCAG 2.1 AA, they may still be in violation of subpart I if a single person with a disability is unable to access some portion of their web content or mobile app. This lack of certainty would prove difficult for recipients and result in confusion throughout health and human services programs and activities.

Comment: Some commenters expressed the view that not all instances of nonconformance to WCAG 2.1 Level AA should be treated equally. Some stated that there should be higher consequences based on how frequently accessed the content is, how egregious the violation is, and whether an issue is inherently more serious.

Response: The Department will investigate all alleged violations of section 504, including alleged nonconformance to WCAG 2.1 Level AA. During the investigation process, the Department may choose to pursue different methods of investigation and remedies depending on the specifics of the alleged violation, including the impact on people with disabilities and the importance of the content in question.

Comment: Some commenters stated that isolated or temporary instances of nonconformance to WCAG 2.1 Level AA should generally not be treated as violations as long as the recipient in question is not a repeat offender, they notify the public of the issue, they remediate the issue in a set period of time, and the issue itself is small.

Response: The Department has considered all of the comments it received on this issue and, based on the comments and its own independent assessment, decided not to separately excuse a recipient's isolated or temporary noncompliance with § 84.84(b) due to maintenance or repairs in the final rule. Rather, as stated in § 84.89, a recipient's legal responsibility for an isolated or temporary instance of nonconformance to WCAG 2.1 Level AA will depend on whether the isolated or temporary instance of nonconformance—as with any other nonconformance—would affect the ability of individuals with disabilities to use the recipient's web content or mobile app in a substantially equivalent way.

The Department believes it is likely that the approach set forth in § 84.89 reduces the need for a provision that would explicitly allow for instances of isolated or temporary noncompliance due to maintenance or repairs, while simultaneously limiting the negative impact of such a provision on individuals with disabilities. The Department believes this is true for two reasons.

First, to the extent isolated or temporary noncompliance due to maintenance or repairs occur that affect web content or mobile apps, it logically follows from the requirements in § 84.84 that these interruptions should generally result in the same impact on individuals with and without disabilities after the compliance date because, in most cases, all users would be relying on the same content, and so interruptions to that content would impact all users. From the compliance date onward, accessible web content and mobile apps and the web content and mobile apps used by people without disabilities should be one and the same (with the rare exception of conforming alternate versions provided for in § 84.86). Therefore, the Department expects that isolated or temporary noncompliance due to maintenance or repairs generally will affect the ability of people with disabilities to use web content or mobile apps to the same extent it will affect the experience of people without disabilities. For example, if a website is undergoing overnight maintenance and so an online form is temporarily unavailable, the form would already conform to WCAG 2.1 Level AA, and so there would be no separate feature or form for individuals with disabilities that would be affected while a form for people without disabilities is functioning. In such a scenario, individuals with and without disabilities would both be unable to access web content, such that there would be no violation of this rule.

Thus, the Department believes that a specific provision regarding isolated or temporary noncompliance due to maintenance or repairs is less necessary than it is for physical access. When there is maintenance to a feature that provides physical access, such as a broken elevator, access for people with disabilities is particularly impacted. In contrast, when there is maintenance to web content or mobile apps, people with and without disabilities will generally both be denied access, such

[206] 45 CFR 84.77.

[207] *See, e.g.,* W3C, *Web Content Accessibility Guidelines (WCAG) 2.1, Success Criterion 2.3.1. Three Flashes or Below Threshold* (June 5, 2018), *https://www.w3.org/TR/2018/REC-WCAG21-20180605/#three-flashes-or-below-threshold* [*https://perma.cc/A7P9-WCQY*] (addressing aspects of content design that could trigger seizures or other physical reactions).

that no one is denied access on the basis of disability.

Second, even to the extent isolated or temporary noncompliance due to maintenance or repairs affects only an accessibility feature, that noncompliance may fit the parameters laid out in § 84.89 such that a recipient will be deemed to have complied with its obligations under the rule. Section 84.89 does not provide a blanket limitation that would excuse all isolated or temporary noncompliance due to maintenance or repairs, however. The provision's applicability would depend on the particular circumstances of the interruption and its impact on people with disabilities. It is possible that an interruption that only affects an accessibility feature will not satisfy the elements of § 84.89 and a recipient will not be deemed in compliance with § 84.84. Even one temporary or isolated instance of nonconformance could affect the ability of individuals with disabilities to use the web content with substantially equivalent ease of use, depending on the circumstances. As discussed above, this will necessarily be a fact-specific analysis.

In addition to being less necessary than in the physical access context, the Department also believes a specific provision regarding isolated or temporary interruptions due to maintenance or repairs would have more detrimental incentives in the digital space by discouraging recipients from adopting practices that would reduce or avert the disruptions caused by maintenance and repair that affect accessibility. Isolated or temporary noncompliance due to maintenance or repairs of features that provide physical access would be necessary regardless of what practices recipients put in place,[208] and the repairs and maintenance to those features often cannot be done without interrupting access specifically for individuals with disabilities. For example, curb ramps will need to be repaved and elevators will need to be repaired because physical materials break down. In contrast, the Department believes that, despite the dynamic nature of web content and mobile apps, incorporating accessible design principles and best practices will generally enable recipients to anticipate and avoid many instances of isolated or temporary noncompliance due to maintenance or repairs—including many isolated or temporary instances of noncompliance that would have such a significant impact that they would affect people with disabilities' ability to use web content or mobile apps in a substantially equivalent way. Some of these best practices, such as regular accessibility testing and remediation, would likely be needed for recipients to comply with subpart I regardless of whether the Department incorporated a provision regarding isolated or temporary interruptions. And practices like testing content before it is made available will frequently allow maintenance and repairs that affect accessibility to occur without interrupting access, in a way that is often impossible in physical spaces. The Department declines to adopt a limitation for isolated or temporary interruptions due to maintenance or repairs. Such a limitation may disincentivize recipients from implementing processes that could prevent many interruptions from affecting substantially equivalent access.

Comment: Commenters mentioned specific laws or policies used by States, including California and Texas, which require covered entities to post certification of their sites' accessibility and submit to testing by the state comptroller, respectively. Some commenters pointed to different technical standards instead.

Response: The Department has considered many States' approaches to assessing compliance with their web accessibility laws [209] and declines to adopt these laws at the Federal level. State laws like those in Florida, Illinois, and Massachusetts, which do not specify how compliance will be measured or how entities can demonstrate compliance, are essentially requiring 100 percent compliance with a technical standard. This approach is not feasible for the reasons discussed earlier in this section. In addition, this approach is not feasible because of the large number and wide variety of recipients covered by section 504, as compared with the relatively limited number of State agencies in a given State. Laws like California's, which require entities covered by California's law to certify or post evidence of compliance, would impose administrative burdens on recipients similar to those imposed by the international approaches discussed below. Some State agencies, including in California, Minnesota, and Texas, have developed assessment checklists, trainings, testing tools, and other resources. The Department may also provide further guidance about best practices for a recipient to meet its obligations under this rule. However, such resources are not substitutes for clear and achievable regulatory requirements. Some commenters stated that regulations should not be combined with best practices or guidance, and further stated that testing methodologies are more appropriate for guidance. The Department agrees and believes recipients are best suited to determine how they will comply with the technical standard, depending on their needs and resources.

The Department also declines to adopt a model like the one used in Texas, which requires State agencies to, among other steps, conduct tests with one or more accessibility validation tools, establish an accessibility policy that includes criteria for compliance monitoring and a plan for remediation of noncompliant items, and establish goals and progress measurements for accessibility.[210] This approach is one way recipients may choose to ensure that they comply with this rule. However, as noted above when discussing the policy-based approach, the Department is unable to calibrate requirements that provide sufficient predictability and certainty for every recipient while maintaining sufficient flexibility. The Department declines to adopt an approach like Texas's for the same reasons it declined to adopt a policy-based approach.

The Department has also determined that other specific international approaches to evaluating compliance with web accessibility laws are currently not feasible to adopt in the United States.[211] The methodologies used by the European Union and Canada require reporting to government agencies.[212] This would pose counterproductive logistical and administrative difficulties for recipients and the Department. The Department believes that the resources recipients would need to spend on data collection and reporting would detract from efforts to increase the accessibility of web content and mobile apps. New

[208] *See* 28 CFR part 35, appendix B at 705 (''It is, of course, impossible to guarantee that mechanical devices will never fail to operate.'')

[209] 88 FR 63392, 63445–46 (Sept. 14, 2023).

[210] 1 Tex. Admin. Code 206.50, 213.21; Tex. Dep't of Info. Res., *EIR Accessibility Tools & Training, https://dir.texas.gov/electronic-information-resources-eir-accessibility/eir-accessibility-tools-training* [*https://perma.cc/A5LC-ZTST*].

[211] *See* 88 FR 51948, 51980 (Aug. 4, 2023) (explaining existing methods for measuring compliance in Canada, the European Union, New Zealand, and the United Kingdom).

[212] Commission Implementing Decision (EU) 2018/1524 (Dec. 10, 2018), *https://eurlex.europa.eu/eli/dec_impl/2018/1524/oj* [*https://perma.cc/5M7B-SVP9*]; Government of Canada, Standard on Web Accessibility (Aug. 1, 2011), *https://www.tbssct.gc.ca/pol/doc-eng.aspx?id=23601&section=html* [*https://perma.cc/ZU5D-CPQ7*].

Zealand's approach,[213] which requires testing and remediation, is similar to the policy-based approach already discussed in this section, and the Department declines to adopt that approach for the reasons stated above. The approach taken in the United Kingdom, where a government agency audits websites and mobile apps, sends a report to the entity, and requires the entity to fix accessibility issues,[214] would raise similar logistical and administrative difficulties for recipients and the Department. Though the Department will continue to investigate complaints and enforce the section 504, given constraints on its resources and the large number of recipients within its purview to investigate, the Department is unable to guarantee that it will conduct a specific amount of enforcement under this rule on a particular schedule.

Given the number of recipients, the wide range in their uses of web content and mobile apps, and the Department's existing compliance activities, such arrangements would not be logistically feasible for section 504. Laws that require 100% conformance to WCAG are not feasible for section 504 for the reasons mentioned above. Laws that establish a single accessibility policy would not allow the hundreds of thousands of HHS recipients sufficient flexibility to determine how to ensure their web content and mobile apps comply with section 504.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are editing § 84.89 to formalize a method for measuring compliance. Specifically, we are finalizing a method of measuring compliance where a recipient that is not fully in compliance with § 84.84(b) will be deemed to have met the requirements of § 84.84 if the recipient can demonstrate that the noncompliance has a minimal impact on access. Whether the noncompliance has minimal impact on access depends on whether the noncompliance would not affect the ability of individuals with disabilities to access the same information, engage in the same interactions, conduct the same transactions, and otherwise participate in or benefit from the same programs and activities with substantially equivalent timeliness, privacy, independence, and ease of use.

Accessible Medical Equipment (Subpart J)

Subpart J addresses requirements related to providing accessible medical equipment for people with disabilities.

Application (§ 84.90)

Proposed § 84.90 stated that this subpart would apply to programs or activities that receive Federal Financial assistance and recipients that operate, or receive Federal financial assistance from the operation of, such programs or activities.

We received no comments on § 84.90.

Summary of Regulatory Changes

The Department is finalizing § 84.90 as proposed with no modifications.

Requirements for Medical Diagnostic Equipment (§ 84.91)

Proposed § 84.91 contained a general requirement that no individual with a disability shall be excluded from or denied the benefits of a program or activity of a recipient offered through MDE due to the inaccessibility of the recipient's MDE.

The comments and our responses regarding § 84.91 are set forth below.

Comment: Almost all commenters supported requiring recipients to ensure the availability of accessible MDE for health equity and access to needed care for people with disabilities. A wide array of stakeholders including disability rights advocates and organizations, individuals with disabilities, civil rights, faith-based, and reproductive rights advocacy groups, as well as medical providers, researchers, State and local jurisdictions, and public health groups all expressed support for incorporating the Access Board's MDE standards into this section 504 regulation.

Response: The Department agrees with commenters that accessible MDE is vital for health equity, person-centered care, and access to care for patients with disabilities. The support for providing accessible care comes from a variety of commenters and recipient groups including physicians, nurses, allied professions, hospital associations, medical suppliers, and others. As discussed in the preamble to our NPRM, researchers have demonstrated and documented that the scarcity of accessible MDE constitutes a significant barrier to access to care for patients with disabilities, resulting in a lack of preventative care and diagnostic exams, while contributing to poorer health outcomes and lower life expectancies. The Department hopes that implementation of this final rule will make a tangible difference.

Comment: Many commenters described the importance of accessible MDE and provided firsthand accounts of instances where they were unable to receive health care or received substandard care because recipients did not utilize accessible exam tables, scales, radiological or other diagnostic equipment. Commenters recounted instances when they were unable to receive prostate exams, mammograms, or skin biopsies or when they received incomplete physical exams because they could not transfer to an exam table. Other commenters noted that they could not have their weight checked regularly because of the lack of an accessible weight scale resulting in an inability to document unexpected weight loss or to track a child's weight and growth over time. Some commenters described recipients' expectations that individuals with mobility disabilities would be accompanied by companions to physically transfer them onto MDE. Some disability advocacy groups shared representative accounts submitted by a number of people documenting the harms experienced by people with disabilities due to recipients who lacked accessible MDE.

Response: The Department is aware of many instances where people with disabilities were denied access to needed care, subjected to demeaning situations, or received substandard care because recipients did not utilize accessible exam tables, weight scales, radiological, or other diagnostic equipment. OCR has taken action to enforce section 504 as it applies to medical care. However, the lack of standards for accessible MDE before the Access Board completed its standards in early 2017, the lack of scoping and rulemaking to make these standards enforceable for recipients, and modest voluntary adoption of accessible MDE by health care providers mean that these circumstances remain all too prevalent. This rulemaking and its effective date will be turning points in ensuring improved access to diagnostic services

[213] New Zealand Government, 2017 Web Standards Self-Assessments Report (July 2018), *https://www.digital.govt.nz/dmsdocument/97-2017-web-standards-self-assessments-report/html* [*https://perma.cc/3TQ3-2L9L*]; New Zealand Government, Web Standards Risk Assessment (Oct. 19, 2020), *https://www.digital.govt.nz/standardsand-guidance/nz-government-web-standards/riskassessment/* [*https://perma.cc/N3GJ-VK7X*]; New Zealand Government, About the Web Accessibility Standard (Mar. 3, 2022), *https://www.digital.govt.nz/standards-and-guidance/nzgovernment-web-standards/web-accessibility standard-1-1/about-2/* [*https://perma.cc/GPR4-QJ29*].

[214] United Kingdom, Understanding accessibility requirements for public sector bodies (Aug. 22, 2022), *https://www.gov.uk/guidance/accessibility requirements-for-public-sector-websites-and-apps;* United Kingdom, Public sector website and mobile application accessibility monitoring (Nov. 1, 2022), *https://www.gov.uk/guidance/public-sector-websiteand-mobile-application-accessibility-monitoring.*

for people with disabilities. Because many people with disabilities are unable to receive even basic health care services as a result of inaccessible exam tables and weight scales, and because many health care providers, including primary care physicians, use exam tables and weight scales and the equipment is relatively inexpensive compared to other accessible MDE such as imaging equipment, the Department decided to add a specific requirement for exam tables and weight scales at § 84.92(c). At a minimum, recipients must acquire one accessible exam table, if they use exam tables, and one accessible weight scale, if they use weight scales, within two years. The Department decided on a two-year time period because it believes that is a sufficient period for most recipients to budget for and acquire accessible exam tables and weight scales. Some commenters were concerned that two years would be too long considering the availability and affordability of accessible exam tables and weight scales measured against the negative health outcomes experienced by people with disabilities when waiting for recipients to acquire accessible MDE, but the Department recognizes recipients will need some time to acquire accessible exam tables and weight scales. This requirement will help address the specific denials of service raised by commenters relating to the inaccessibility of exam tables and weight scales, and ensure that regardless of recipient size, as long as recipients use at least one exam table or weight scale, patients will have access to accessible exam tables and weight scales. The Department also chose to specify exam tables and weight scales because exam tables and weight scales that meet the MDE Standards are already available on the open market and are less expensive than some other available accessible MDE, such as imaging equipment.[215]

Comment: A few medical provider groups expressed concerns about the extension of responsibility for these provisions to facilities not directly controlled by the section 504 covered recipient, giving an example of an emergency department boarding patients for other departments when inpatient beds or appropriate transfers are unavailable. These groups sought clarification of whether accessible MDE responsibilities will apply in these cases and requested a collaborative approach with the Department rather than being held accountable for decisions beyond their control, and consideration when complying with these requirements would result in undue burden.

Response: Since its publication in 1977, the Department's section 504 regulations have applied to recipients of Federal financial assistance from the Department. This rulemaking does not change the recipients covered by section 504. This rulemaking applies to each recipient and to the program or activity that receives such assistance. In the unlikely circumstance that a health care provider that receives financial assistance from the Department uses the facilities of a health care provider that does not accept financial assistance from the Department, the recipient is still required to comply with section 504 and all other appropriate Federal civil rights laws. Section 84.68(b)(1)(i) in the general prohibitions against discrimination section states that a recipient, in providing any aid, benefit, or service, may not, directly or through contractual, licensing, or other arrangement deny a qualified individual the opportunity to participate in or benefit from the aid, benefit, or service that is not equal to that afforded others. Paragraphs (b)(1)(ii) through (vii) list other types of discrimination prohibited by recipients whether directly or through contractual, licensing, or other arrangements.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.91 as proposed with no modifications.

Newly Purchased, Leased, or Otherwise Acquired Medical Diagnostic Equipment (§ 84.92)

Proposed § 84.92(a) required that all MDE that recipients acquire more than 60 days after final publication of this rule must meet the Standards for Accessible MDE until the recipient satisfies scoping requirements in § 84.92(b). Proposed § 84.92(b) contained specific scoping requirements for accessible MDE ranging from 10% to 20% of all MDE based on facility specialty or purpose. We invited comment on the following questions:

- *MDE Question 1: The Department seeks public comment on whether and how to apply the existing scoping requirements for patient or resident sleeping rooms or parking spaces in certain medical facilities to MDE; and on whether there are meaningful differences between patient or resident sleeping rooms, accessible parking, and MDE that the Department should consider when finalizing the scoping requirements.*
- *MDE Question 2: The Department seeks public comment on whether different scoping requirements should apply to different types of MDE, and if so, what scoping requirements should apply to what types of MDE.*
- *MDE Question 3: Because more patients with mobility disabilities may need accessible MDE than need accessible parking, the Department seeks public comment on whether the Department's suggested scoping requirement of 20 percent is sufficient to meet the needs of persons with disabilities.*
- *MDE Question 4: The Department seeks public comment on any burdens that this proposed requirement or a higher scoping requirement might impose on recipients.*
- *MDE Question 5: The Department seeks public comment on whether the proposed approach to dispersion of accessible MDE is sufficient to meet the needs of individuals with disabilities, including the need to receive different types of specialized medical care.*
- *MDE Question 6: The Department seeks public comment on whether additional requirements should be added to ensure dispersion (e.g., requiring at least one accessible exam table and scale in each department, clinic, or specialty; requiring each department, clinic and specialty to have a certain percentage of accessible MDE).*
- *MDE Question 7: The Department seeks information regarding:*
  - *The extent to which accessible MDE can be moved or otherwise shared between clinics or departments.*
  - *The burdens that the rule's proposed approach to dispersion or additional dispersion requirements may impose on recipients.*
  - *The burdens that the rule's proposed approach to dispersion may impose on people with disabilities (e.g., increased wait times if accessible MDE needs to be located and moved, embarrassment, frustration, or impairment of treatment that may result if a patient must go to a different part of a hospital or clinic to use accessible MDE).*

We proposed in § 84.92(c) to require recipients that use exam tables must acquire at least one accessible exam table within two years of the final publication of this rule. We proposed the same requirement for recipients that use weight scales. As noted above, we decided that accessible exam tables and

[215] *See, e.g.,* 82 FR 2810, 2829 (Jan. 9, 2017) (stating that commenters were concerned about immediate compliance with the MDE Standards for ''more expensive imaging equipment'' compared to other accessible MDE). *See also 2024 Mammography Price Guide,* Block Imaging, *https://www.blockimaging.com/bid/95356/digital-mammography-equipment-price-cost-info* (last visited Feb. 20, 2024).

weight scales should be included in this requirement because many primary care health care providers use them for a range of basic diagnostic services. Additionally, accessible exam tables and weight scales are available on the open market and more affordable when compared to other accessible MDE, such as imaging equipment.[216] Finally, we proposed a two year time period to acquire an accessible exam table and accessible weight scale because while that MDE is currently available, we understand that some recipients may need additional time to budget for and acquire it. We did not propose a longer time period because, as commenters note below, the inability to receive even basic health care services because of inaccessible exam tables and weight scales results in negative health outcomes for people with disabilities. We invited comment on the following questions:

- *MDE Question 8: The Department seeks public comment on the potential impact of the requirement of paragraph (c) on people with disabilities and recipients, including the impact on the availability of accessible MDE for purchase and lease.*
- *MDE Question 9: The Department seeks public comment on whether two years would be an appropriate amount of time for the requirements of paragraph (c); and if two years would not be an appropriate amount of time, what the appropriate amount of time would be.*

We proposed in § 84.92(d) to make clear that recipients may use alternative standards to those required by the Standards for Accessible MDE as long as the alternative standards result in substantially equivalent or greater accessibility and usability.

We proposed in § 84.92(e) to provide that this section would not require a recipient to take actions that would result in a fundamental alteration in the nature of a program or activity, or in undue financial and administrative burdens, while providing additional clarity on claiming these exceptions.

We proposed in § 84.92(f) to provide that recipients could prove that compliance with § 84.92(a) or (c) would be a fundamental alteration if compliance would alter diagnostically required structural or operational characteristics of the equipment, and prevent the use of the equipment for its intended diagnostic purpose.

The comments and our responses to § 84.92 are set forth below.

Comment: Most recipient organizations acknowledged the need to provide accessible MDE to people with disabilities and generally supported the accessible MDE provisions with scoping as proposed in the NPRM. Many recipient organizations expressed appreciation of the Department's measured approach and expressed support for provisions offering providers flexible approaches to compliance, particularly for small provider organizations with fewer than fifteen employees and the proposals at § 84.22(c) for existing facilities allowing alternative compliance schemes. A minority of groups representing physician, dental, hospital and insurance providers expressed concerns with costs for small recipients and requested longer phase-in periods, extensions for small recipients if recent MDE purchases had been made, or in some cases, requiring all new purchases to be accessible MDE as opposed to requiring that practices have a minimum number or percentage of accessible equipment. A number of health care provider groups requested technical or financial assistance in support of their efforts to come into compliance.

Response: The Department appreciates provider groups' recognition of the importance of these provisions for people with disabilities, as well as their support for the nuanced approach the Department is taking with scoping. The Department declines to extend the phase-in period, offer extensions for small practices which recently procured MDE, or to only require newly purchased equipment to be accessible at this time. This is because the health disparities and barriers to access-to-care people with disabilities are facing are urgent [217] and extending phase-in periods will extend the time that they must wait for necessary services. Many people with disabilities have been urging the Department to make the MDE Standards mandatory since the Access Board issued them in 2017. Additionally, recipients have had considerable notice that these standards were under development, given that the ACA, enacted in 2010, directed the Access Board to promulgate standards for MDE.[218] Recipients were also on notice since the Access Board issued the MDE Standards in 2017 that enforcing agencies might make the standards enforceable.[219]

Finally, with the defenses of fundamental alteration and undue burden, this regulation already includes a carefully calibrated balance of interests to account for the burden on smaller recipients.

Comment: Many disability advocates, disability rights advocacy organizations, a member of Congress, and some State and local jurisdictions voiced concerns that the proposed scoping provisions were inadequate to meet demand among people with mobility disabilities. Many commenters dismissed using parking space percentages, which assume time-limited use of designated slots, as an inappropriate model for MDE scoping for facilities providing medical services

[216] *See* U.S. Access Board, Access Board Review of MDE Low Height and MSRP, (May 23, 2023), *https://www.regulations.gov/document/ATBCB-2023-0001-0002* (listing available exam table models that meet the height requirements of the MDE Standards, and their retail prices). Additionally, based on conversations with recipients, Federal partners, and advocacy organizations, and as supported in the comments received, accessible weight scales are more prevalent and affordable than accessible exam tables. On the affordability of accessible exam tables and weight scales compared to imaging equipment, *see* 82 FR 2810, 2829 (Jan. 9, 2017) (stating that commenters were concerned about immediate compliance with the MDE Standards for ''more expensive imaging equipment'' compared to other accessible MDE). *See also 2024 Mammography Price Guide,* Block Imaging, *https://www.blockimaging.com/bid/95356/digital-mammography-equipment-price-cost-info* (last visited Feb. 20, 2024).

[217] *See* CB Steele et al., *Prevalence of Cancer Screening Among Adults With Disabilities, United States, 2013,* 14 Preventing Chronic Disease (Jan. 2017), *https://www.cdc.gov/pcd/issues/2017/16_0312.htm* (finding disparate access to cancer screenings); Gloria Krahn, *Persons with Disabilities as an Unrecognized Health Disparity Population,* 105 Amer. J. Public Health 198 (Apr. 2015), *https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4355692/* (finding higher prevalence of obesity and cardiovascular diseases). *See also* Michael Karpman et al., Urban institute Health Policy Center, QuickTake: Even with Coverage, Many Adults Have Problems Getting Health Care, with Problems Most Prevalent among Adults with Disabilities, (Sept. 2015), *https://apps.urban.org/features/hrms/quicktakes/Many-Adults-Have-Problems-Getting-Health-Care.html#:~:text=Adults%20with%20disabilities%20were%20also,to%20get%20to%20a%20doctor's;* Henning Smith, *Delayed and Unmet Need for Medical Care Among Publicly Insured Adults with Disabilities,* 51 Medical Care 1015, (Nov. 2013), *https://pubmed.ncbi.nlm.nih.gov/24113815/;* Amanda Reichard et al, *Prevalence and Reasons for Delaying and Foregoing Necessary Care by the Presence and Type of Disability Among Working-age Adults,* 10 Disability and Health J. 39, (Jan. 2017), *https://pubmed.ncbi.nlm.nih.gov/27771217/;* Michelle Stransky et al., *Provider Continuity and Reasons for not Having a Provider Among Persons With and Without Disabilities,* 12 Disability and Health J. 131, (Jan. 2019), *https://pubmed.ncbi.nlm.nih.gov/30244847/;* Sarah Bauer et al., *Disability and Physical and Communication-related Barriers to Health Care Related Services Among Florida Residents: A Brief Report,* 9 Disability and Health J. 552, (July 2016), *https://pubmed.ncbi.nlm.nih.gov/27101882/* (finding barriers to access to care).

[218] Section 4203 of the Affordable Care Act, 42 U.S.C. 18001 *et seq.,* amending the Rehabilitation Act to add section 510, 29 U.S.C. 794f.

[219] 82 FR 2810 (explaining that ''other agencies, referred to as enforcing authorities in the MDE Standards, may issue regulations or adopt policies that require health care providers subject to their jurisdiction to acquire accessible medical diagnostic equipment that complies with the MDE Standards'').

frequented by a growing population of patients with disabilities. Without a larger percentage or all equipment being accessible, they asserted that patients with disabilities will have fewer scheduling options than their nondisabled counterparts. Instead, some commenters suggested using standards now applied to transportation retrofits.

Many commenters felt that 10% and 20% were inadequate percentages for accessible MDE because of demographic trends and the belief that accessible MDE would be considerably more in demand than parking spaces, especially since nondisabled drivers often drive their relatives with disabilities to these facilities, while those who need accessible MDE can only utilize the accessible equipment. Those commenters either proposed higher percentage thresholds for compliance, such as 20% and 40%, or that facilities require all newly purchased and leased MDE to be accessible. Some commenters also noted that the cost difference between accessible and inaccessible scales is negligible, so thresholds for scales could be instituted in a shorter time frame. An individual with disabilities objected to having to wait two more years for accessible MDE after they already waited 50 years from the adoption of section 504 and warned that an additional two-year waiting period would put the health of some people with disabilities at risk and even result in untimely deaths. An independent Federal agency charged with advising the President, Congress, and other Federal agencies on policies, programs, practices, and procedures that affect people with disabilities also objected to the two-year implementation timeline, recommending instead one year for exam tables and 120 days for scales. A commenter from the health advocacy field noted the absence of timelines for accessible MDE beyond scales and medical exam tables and requested the Department set an outer limit for compliance with these provisions at two years.

While several disability commenters opposed varying percentage requirements for different covered entities because of the difficulties in identifying which specialties are most vital to people with disabilities, others supported higher requirements for facilities whose patient census includes large numbers of people with mobility disabilities.

Response: The Department appreciates the concerns of commenters seeking more stringent scoping and recognizes that the needs for accessible parking are not perfectly aligned with the needs underpinning accessible MDE. While parking spaces and MDE are not used in the exact same manner and may not be used with the same consistency, the limited use of MDE is analogous to the use of parking spaces at a rehabilitation facility because, as with parking spaces, multiple patients with mobility disabilities could use the same piece of MDE in a day. Additionally, the use of MDE is not analogous to the use of vehicles covered by transportation regulations, which address a transportation system, rather than the accessibility of individual units of equipment, as under this rule.[220] Weight scales and exam tables also typically cannot be retrofitted to be accessible with the same ease or cost ratio compared to acquiring accessible MDE. Inaccessible weight scales typically do not have large platforms that are required for wheelchair access. Inaccessible exam tables are usually fixed height ''box'' tables with static bases, and possibly drawers, that are not easily or cheaply replaced with adjustable mechanisms.[221]

Section 84.91 states that recipients may not exclude, deny benefits to, or otherwise discriminate against people with disabilities in programs or activities that use MDE. Additionally, § 84.93 requires that each program or activity that uses MDE be readily accessible to and usable by people with disabilities in its entirety independent of the scoping requirements for newly acquired MDE set forth in § 84.92. Acquiring additional accessible MDE is one method to ensure that recipients do not exclude, deny benefits to, or otherwise discriminate against people with disabilities in programs or activities that use MDE, but it is not the only method. If a recipient denies a physical exam to a patient with a disability before the recipient is required to have an accessible exam table, they may still violate the other provisions of section 504.

As noted above, the Department imposed specific requirements for exam tables and weight scales because of their ubiquity among primary care providers, their importance for basic diagnostic health services, and their relative attainability compared to more expensive accessible imaging equipment.[222] We did not propose a longer time period because the inability to receive even basic health care services because of inaccessible exam tables and weight scales results in negative health outcomes for people with disabilities. Additionally, we did not propose a shorter time period because we recognize that some recipients, especially small recipients with fewer resources, will need sufficient time to budget for and acquire accessible exam tables and weight scales.

Recipients that provide services that rely on other MDE are still required to provide those services to patients with disabilities, but section 504 will not require those recipients to acquire other accessible MDE (unless the requirements for all newly purchased, leased, or otherwise acquired MDE set forth in § 84.92(a) apply) if they are able to make their programs and activities accessible through other means.

In view of demands on recipients, particularly small practices and rural facilities, the Department will not require all newly acquired MDE, beyond the requirements set forth in § 84.92, to be accessible at this time or shorten the two-year implementation timeline. The utility of additional pieces of accessible MDE may be limited, given that multiple patients with mobility disabilities can use the same accessible MDE. Additionally, many recipients are small entities that only use a small amount of MDE. This means that regardless of whether the scoping requirement is 10%, 20%, or even 40%, many recipients would only be required to acquire one piece of accessible MDE.[223]

While the Department will not increase the scoping requirements of proposed § 84.92, recipients may determine that the most effective method to comply with the program access obligation set forth in § 84.93 will be to acquire additional accessible MDE beyond that required by § 84.92. In addition, the nondiscrimination provisions in §§ 84.68(a) and 84.91 continue to apply.

Comment: A few commenters suggested different scoping

[220] 49 CFR part 37.

[221] ADA National Network, Accessible Medical Examination Tables and Chairs, *https://adata.org/factsheet/accessible-medical-examination-tables-and-chairs* (last visited March 1. 2024).

[222] *See* U.S. Access Board, Access Board Review of MDE Low Height and MSRP (May 23, 2023), *https://www.regulations.gov/document/ATBCB-2023-0001-0002* (listing available exam table models that meet the height requirements of the MDE Standards, and their retail prices). On the affordability of accessible exam tables and weight scales compared to imaging equipment, *see* 82 FR 2810, 2829 (Jan. 9, 2017) (stating that commenters were concerned about immediate compliance with the MDE Standards for ''more expensive imaging equipment'' compared to other accessible MDE). *See also 2024 Mammography Price Guide,* Block Imaging, *https://www.blockimaging.com/bid/95356/digital-mammography-equipment-price-cost-info* (last visited Feb. 20, 2024).

[223] Tables 18 and 19 of the Regulatory Impact Analysis provide estimates for the numbers of employees and accessible MDE that recipients will acquire in response to this rulemaking.

requirements to reflect the omission of higher weight patients from the Standards for Accessible MDE by adding higher capacity equipment.

Response: The Department is not in a position to use scoping to address omissions from the MDE Standards developed by the Access Board as a part of this final rule.[224] However, these comments will be noted and relayed to the Access Board.

Comment: Some commenters asked whether MDE or medical treatment equipment used in home settings is covered under this rulemaking. Some commenters made the assumption that such equipment was covered. Although some commenters supported such application as urgently needed, others cautioned that it could add unforeseen burden to recipients or even impede access to home-based care.

Response: The obligations set forth in this rule apply to ''program[s] or activit[ies] offered through or with the use of MDE,'' and are subject to the limitations set forth in the rule, including the undue burden limitation. Whether recipients would need to ensure that MDE used in the provision of health care programs or activities in home settings complied with the MDE Standards would depend on the particular factual circumstances. Regarding the comments about the application of this rule to medical treatment equipment, while the Department inquired about application of these standards to non-diagnostic equipment as a part of MDE Question 14 for future consideration, the MDE Standards are not being applied to non-diagnostic equipment at this time. Any extension of the MDE Standards or new standards will result from the work of and future standards set by the Access Board, and the Department will relay this information to the Access Board for future consideration.

Comment: Many comments on the Department's proposed dispersion requirements to give larger covered entities flexibility in how they comply with subpart J requirements at § 84.92(b)(3) stated that it is not logistically feasible to share MDE across medical departments. Many disability advocates and public health groups expressed concern that the proposed rule would lead to incomplete or partial accessibility. Without additional safeguards, these groups worry there would be scheduling and logistical issues for providers and patients alike, leading to untimely access to necessary care, and commenters suggested additional statutory requirements or IT infrastructure would be needed to coordinate availability of accessible MDE. Some groups noted that some MDE isn't sufficiently portable to support the flexible compliance scheme the Department envisioned, particularly if equipment is being shared beyond one floor, building, or campus. A State cautioned that the experience of trying to serve at-risk populations with scarce resources during COVID–19 could prove instructive in anticipating the challenges medical facilities would have providing accessible MDE to considerable numbers of people with mobility disabilities. Further, commenters stressed that strategies to achieve compliance that rely on patients travelling between remote campuses are infeasible for the many people with mobility disabilities who may lack ready access to transportation. Alternatively, some provider groups expressed appreciation for a flexible approach to problem-solving and meeting patients' needs.

Response: The Department appreciates the comments on its proposed dispersion requirements. This provision does not require exact mathematical proportionality, which at times would be impossible. The Department agrees that there may be situations where a recipient with multiple departments, clinics, or specialties will not be able to simply disperse its accessible MDE proportionally across all departments, clinics, or specialties. If a recipient requires a patient with a disability who requires accessible MDE to use the MDE of another department, the recipient must ensure that the accessible MDE is readily accessible to and usable by the patient. Factors to consider in determining whether this standard has been met may include, among other things, whether the MDE is readily available and not a significant distance from where the patient is seeking care; whether changing locations during the patient visit significantly increases wait times; whether the patient is required to be undressed or partially dressed to use the MDE (if, for example, the patient has to go to a different part of the same building to use the accessible MDE); and whether the recipient provides assistance moving between locations. This means that some of the situations commenters described, including going to a separate campus or building to use a recipient's accessible MDE, could result in the recipient's program or activity not being readily accessible to and usable by patients with disabilities as required by § 84.93(a). Recipients must ensure that the dispersal of their accessible MDE does not discriminate against people with disabilities.

The Department also recognizes there may be situations where small recipients with a limited number of departments, clinics, or specialties in the same building may have one piece of accessible MDE that is shared among all departments, clinics, or specialties in a manner that provides access for all patients with disabilities who require access to the accessible MDE. The Department recommends as a best practice that where a recipient in a large facility with many departments, clinics, or specialties uses MDE, recipients have at least one piece of accessible MDE in each department, clinic, or specialty to limit instances where patients with disabilities must traverse between departments, clinics, or specialties for care.

Comment: The Department received many comments with suggestions for alternative requirements or methods for the placement of accessible MDE. Many disability and public health group commenters supported the alternative of requiring at least one exam table and scale per department, as a minimum, utilizing dispersion only as an interim measure. One commenter requested further clarity on how rules would apply to facilities with multiple non-adjacent campuses. Other disability organizations suggested requiring facilities to provide accessible transportation between facilities at no cost to the patient if necessary to secure timely access to MDE, or providing access to MDE via home visits. Similarly, one public health foundation expressed concern the NPRM did not recognize the burden imposed on people with disabilities of having to travel further or wait longer to access MDE. By contrast, many provider groups expressed concern about the cost and burden of more prescriptive approaches including one exam table and scale for each component of a medical facility.

Response: As noted in the Department's response above, recipients are encouraged to obtain at least one piece of accessible MDE for each department that uses that MDE. However, due to the varying sizes,

[224] The Rehabilitation Act, as amended by the ACA, directed the Access Board to promulgate technical standards for accessible MDE. 29 U.S.C. 794f. The Access Board's MDE Standards are not binding unless they are adopted by an enforcement agency such as HHS or DOJ. HHS is one of the 12 Federal agencies that are on the Access Board. The Access Board is the agency that can update its standards and HHS, as a member of the Board, participates in issuing updates to those standards. While HHS or another enforcement agency can establish scoping requirements if they adopt the Access Board's standards, neither HHS nor any other Federal agency can amend the Access Board's standards on its own.

patient populations, and circumstances of different recipients, the Department recognizes that recipients in large facilities with multiple departments will not necessarily have to obtain at least one piece of accessible MDE for each of its departments.

Situations where a recipient has multiple campuses and requires a patient who requires accessible MDE to go to different campuses for services from the same department due to the distribution of accessible MDE may constitute violations of § 84.92(b)(3) if the recipient's MDE is not readily accessible to or usable by persons with disabilities. In such situations, however, the recipient may be able to take other measures to ensure that its programs and activities are readily accessible to and usable by the patient. For example, it could offer home visits that provide equal access to care or accessible transportation to the patient with a disability at no cost to them within a reasonable time frame.

Comment: The Department received several comments urging the Department to amend this rule to reflect the Access Board NPRM proposing to revise the Accessible MDE standards by replacing the current 17 to 19 inch low transfer height range with a low transfer height of 17 inches.[225] The Access Board issued this NPRM to revise the height consistent with the findings of recent NIDILRR-funded research that the 17-inch low transfer height better reflects the needs of wheelchair users for safe transfers to examination tables.[226]

Response: The Access Board issued an NPRM that proposed to remove the sunset provision allowing for a 17 to 19 inch low transfer surface height and replace it with a 17-inch low transfer height requirement in May of 2023. As of the drafting of this final rule, the Access Board has not yet finalized the 17-inch low transfer height. As noted in the NPRM, the Department will consider issuing supplemental rulemaking updating the low transfer height requirement once the Access Board's NPRM on transfer height is finalized.

Under this rule, recipients acquiring accessible examination tables have the option acquiring examination tables that lower to between 17 to 19 inches.

As a reminder, under § 84.93(a) recipients are required to operate their programs and activities that use MDE so that they are accessible to people with disabilities, regardless of whether their exam tables lower to 17 or 19 inches.

Comment: A commenter encouraged the Department to work with the Access Board and DOJ on guidance and to consider the General Services Administration's framework for implementing the technology accessibility standards under section 508 of the Rehabilitation Act.

Response: The Department appreciates the recommendation and is committed to creating guidance documents and other technical assistance and providing education to assist recipients with understanding and meeting their obligations, in addition to guidance documents on the MDE Standards that already exist.[227]

Summary of Regulatory Changes

Based on comments we received concerning methods for acquiring accessible MDE, discussed below in the comments and responses concerning § 84.93, we are modifying § 84.92(a) to explicitly recognize that lease renewals, in addition to the purchase, lease, or other acquisition, of MDE, will trigger the requirements of § 84.92(a). The Department's intent was always that lease renewals fall under the umbrella of new purchases, leases, or other methods for acquiring MDE under § 84.92(a), but we recognize that some readers may be confused if lease renewals are not specifically mentioned.

Existing Medical Diagnostic Equipment (§ 84.93)

We proposed in § 84.93 to include clarifications regarding requirements for existing MDE. We proposed in § 84.93(a) to clarify that the program or activity in its entirety must be accessible, which does not necessarily require a recipient to make each of its pieces of MDE accessible, nor does it require a recipient to take an action that would result in a fundamental alteration in the nature of a program or activity, or in undue financial and administrative burdens.

In § 84.93(a)(3) of this final rule, we are correcting a typographical error in the NPRM. Section 84.93(a)(3) of the final rule will state that a recipient meets its burden of proving that compliance with § 84.93(a) would result in a fundamental alteration under § 84.93(a)(2) if it demonstrates that compliance with § 84.93(a) would alter diagnostically required structural or operational characteristics of the equipment and prevent the use of the equipment for its intended diagnostic purpose. The NPRM mistakenly referred to § 84.92(a) and (c) rather than § 84.93(a).

We proposed in § 84.93(b) to state that recipients could comply with this section through other methods beyond the acquisition of accessible MDE where other methods are effective in achieving accessibility of the program or activity. We invited comment on the following questions:

- *MDE Question 10: The Department seeks information about other methods that recipients can use to make their programs and activities readily accessible to and usable by individuals with disabilities in lieu of purchasing, leasing, or otherwise acquiring accessible MDE.*
- *MDE Question 11: The Department seeks information regarding recipients' leasing practices, including how many and what types of recipients use leasing, rather than purchasing, to acquire MDE; when recipients lease equipment; whether leasing is limited to certain types of equipment (e.g., costlier & more technologically complex types of equipment); and the typical length of recipients' MDE lease agreements.*
- *MDE Question 12: The Department seeks information regarding whether there is a price differential for MDE lease agreements for accessible equipment.*
- *MDE Question 13: The Department seeks information regarding any methods that recipients use to acquire MDE other than purchasing or leasing.*
- *MDE Question 14: If this rule were to apply to medical equipment that is not used for diagnostic purposes,*

o *Should the technical standards set forth in the Standards for Accessible Medical Diagnostic Equipment be applied to non-diagnostic medical equipment, and if so, in what situations should those technical standards apply to non-diagnostic medical equipment? Are there particular types of non-diagnostic medical equipment that should or should not be covered?*

The comments and our responses to proposed § 84.93 are set forth below.

Comment: The Department received comments on leasing arrangements and alternatives from disability, public health, and provider groups and State and local jurisdictions. One public health entity advised the Department to conduct a comprehensive survey to better understand leasing practices and their utilization in diagnostic health care delivery. This commenter

[225] 88 FR 33056 (May 23, 2023).

[226] *See, e.g.,* Clive D'Souza, University of Pittsburgh Dep't of Rehabilitation Science and Technology, Analysis of Low Wheelchair Seat Heights and Transfer surfaces for Medical Diagnostic Equipment Final Report (Jan. 2022), *https://www.access-board.gov/research/human/wheelchair-seat-height/.*

[227] *See e.g.,* ADA Nat'l Network, Accessible Medical Diagnostic Equipment, *https://adata.org/factsheet/accessible-medical-diagnostic-equipment* (last visited Dec. 11, 2023).

mentioned that in addition to leasing new equipment, some entities will lease or purchase refurbished units. Other health care providers may receive MDE through donations, long-term borrowing, or pooling and sharing arrangements. One commenter said that about 70% of medical equipment is leased, typically on three to five year contracts but often with early opt-out provisions, and that leases may qualify for tax benefits like IRS section 179. Disability and caregiving commenters specifically warned that lease renewals may be used by recipients to circumvent compliance and urged the Department to revise regulatory language to clarify that lease renewals are considered ''new'' leases. Another disability advocacy organization noted trade-ins and rentals as other possible alternatives to leases.

Response: The Department appreciates these responses. The Department agrees that recipients may not rely on the renewal of leases for existing MDE as a method to avoid acquiring accessible MDE for a prolonged period of time. Accordingly, the Department has edited the regulatory text at § 84.92(a) to clarify that lease renewals will also trigger the requirement to acquire accessible MDE. The intent of the rulemaking was always to require recipients to acquire accessible MDE when a recipient's lease of inaccessible MDE will expire at a set point in the future, when a piece of MDE reaches the end of its useful life and the recipient replaces it, or when a recipient decides to acquire a new piece of MDE for any of a myriad of reasons. Failing to explicitly state that lease renewals are included under § 84.92(a) may suggest that they are not covered and incentivize recipients to renew leases on inaccessible MDE for greater periods than they would have otherwise, extending the period where patients with disabilities do not have access to accessible MDE. Additionally, the Department notes that other arrangements, such as purchasing refurbished units or acquiring MDE through donations, long term borrowing, pooling, or sharing agreements will not exempt recipients from the obligations of § 84.92. Accordingly, the Department clarifies that lease renewals, purchasing refurbished MDE, acquiring MDE through donations, long term borrowing, pooling, and sharing agreements are all considered new purchases, leases, or other acquisitions of MDE under § 84.92 and its scoping standards. Additionally, the Department considers trade-in, rental, and other methods of acquisition of MDE as methods to ''otherwise acquire MDE'' already covered under § 84.92. The intent of this rulemaking is not to provide for loopholes where a recipient, regardless of fundamental alteration or undue burden, can avoid acquiring accessible MDE for long periods of time and avoid providing access to people with disabilities.

Comment: The Department received many comments from diverse stakeholders on whether the Access Board's MDE Standards should be applied to medical equipment beyond MDE. While most commenters supported applying the MDE Standards to non-diagnostic equipment, especially equipment used for therapeutic or treatment purposes, some commenters urged the Department not to do so without further input from interested parties. Disability stakeholders strongly supported these applications and several encouraged the Department to approve standards for a range of medical equipment used primarily for treatment. However, those commenters also stated that the Department lacks technical expertise to impose such standards unilaterally on a broad range of equipment. They therefore suggested the Department coordinate with the Access Board, while also extending new standards to account for blind individuals, people with sensory disabilities, higher weight people, and people with intellectual disabilities. Other commenters advocated for the Department to set standards for equipment used in the home and for telehealth.

Response: The Department agrees that any extension of the MDE standards to non-diagnostic equipment, or any new standards for medical equipment meant to account for additional disabilities, should come with additional input from the Access Board. The Department has been in frequent contact with the Access Board about this rulemaking and the MDE Standards, and would rely heavily on the Access Board's extensive knowledge and technical acumen before altering the MDE Standards or creating new standards. The Department also notes that proposed subpart I covers accessible web content and mobile apps, including telehealth platforms, and requires that recipients conform to the success criteria of WCAG 2.1 AA.

Comment: An association representing dental support organizations asked the Department whether dentists could continue to treat patients who prefer to be treated in their wheelchairs after the effective date of the final rule. This association also raised the issue of the accessibility of exam chairs in instances where plumbing is attached to the chairs in ways that prevent compliance with the standards.

Response: This rule establishes accessibility requirements that recipients that use MDE must comply with. It does not require patients to receive medical services while using accessible MDE if the recipient can provide the benefits of the recipient's programs or activities that the patient requires without the need for the patient to transfer to the accessible MDE, and if the patient prefers not to transfer to the accessible MDE.

In instances where a recipient has decided to use inaccessible exam chairs with plumbing built into the chair, whether replacing one or more of such inaccessible MDE with accessible MDE would constitute an undue burden or fundamental alteration would depend entirely on the individual circumstances of the recipient.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, in § 84.93(a)(3), we are replacing the reference to § 84.92(a) and (c) with a reference to § 84.93(a), and we are finalizing the remainder of § 84.93 as proposed with no other modifications.

Qualified Staff (§ 84.94)

Proposed § 84.94 required that a recipient ensure its staff is able to successfully operate accessible MDE, assist with transfers and positioning of individuals with disabilities, and carry out program access obligations for existing MDE. We invited comment on the following questions:

- *MDE Question 15: The Department seeks general comments on this proposal, including any specific information on the effectiveness of programs used by recipients in the past to ensure that their staff is qualified and any information on the costs associated with such programs.*
- *MDE Question 16: The Department seeks public comment on whether there are any barriers to complying with this proposed requirement, and if so, how they may be addressed.*

The comments and our responses to proposed § 84.94 are set forth below.

Comment: The Department received comments on how to ensure staff are qualified and properly trained from diverse stakeholders. Disability commenters overwhelmingly supported mandatory trainings of recipients on the safe use of accessible MDE, accompanied by modules covering effective communication and person-centered care, developed in consultation with disability rights organizations and advocates with lived experience with

refresher trainings at regular intervals. Commenters asserted that the costs of these trainings would be modest, especially when compared with the costs of worker or patient injury resulting from untrained staff. One commenter asserted that proposed § 84.94, as drafted in the NPRM, was insufficient to ensure recipients train and retrain qualified staff to operate accessible MDE and assist with necessary transfers and positioning to meet recipient program access obligations and safely serve clients. Many commenters agreed that health care providers must be trained on accessible MDE and given guidance on cultural competency in interactions with patients with disabilities, and urged the Department to provide more support and training for recipients.

Finally, some disability commenters, citing personal or aggregated accounts of hospitals asking relatives or companions to lift and transfer patients, requested that we clarify that it is hospital staff, not the patient or their relatives' responsibility, to do lifting and transferring necessary to utilize MDE.

Response: The Department appreciates the comments on qualified staff. As the NPRM notes, often the most effective way for recipients to ensure that their staff are able to successfully operate accessible MDE is to provide staff training on the use of MDE. While it may be in the best interest of recipients to provide training, both for the safety of the patient and the safety of the employee, the Department wishes to provide recipients with flexibility in how they ensure qualified staff. Appropriate training curricula and regimens for a small single-physician providers may differ from those required for large hospital systems.

Although specific trainings are not required, it is worth noting that medical practices and facilities seeking technical assistance on these and other health care accessibility requirements can reference previously issued joint guidance from the Department and the Department of Justice, titled ''Access to Medical Care for Individuals with Mobility Disabilities.'' [228] The Department will consider updating this guidance for consistency with this rulemaking.

Finally, the Department clarifies that, as noted in the NPRM, barring an applicable limitation or defense, a recipient cannot require a patient with a disability to bring someone along with them to help during an exam. A patient may choose to bring another person such as a friend, family member, or personal care aide to an appointment, but regardless, the recipient may need to provide reasonable assistance to enable the patient to receive medical care. Such assistance may include helping a person who uses a wheelchair to transfer from their wheelchair to the exam table or diagnostic chair.[229] The recipient cannot require the person accompanying the patient to assist. We also remind recipients that the provision in the ACA that required the development of these MDE accessibility standards was designed to ''allow independent entry to, use of, and exit from the equipment by such individuals to the maximum extent possible.'' [230]

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.94 as proposed with no modifications.

Subpart K—Procedures

Subpart K contains the procedures for enforcement of this rule.

Procedures (§ 84.98)

Proposed § 84.98, stated that the procedural provisions applicable to title VI of the Civil Rights Act of 1964 apply to the part. Those procedures are found in 45 CFR 80.6 through 80.10 and 45 CFR part 81.

The comments and our responses regarding § 84.98 are set forth below.

Comment: Many commenters expressed concerns about what they viewed as a lack of enforcement procedures in the rule, noting that without ''teeth,'' the regulation is not useful and will have no effect. One commenter urged that the rule contain a means of enforcement other than through filing a lawsuit.

Response: The Department appreciates commenters' concerns about what they believe to be a lack of enforcement procedures in the rule. As noted above, § 84.98 incorporates the compliance procedures of title VI of the Civil Rights Act of 1964 which prohibits discrimination on the basis of race, color, and national origin in federally funded programs. Many other civil rights regulations that apply to recipients of Federal financial assistance similarly incorporate title VI procedures.

The incorporated regulations mandate that the Department conduct proactive periodic compliance reviews without the need for a complaint and also that it investigate complaints filed with it. Any person who believes themselves or any specific class of individuals to have been subjected to discrimination may file a written complaint within 180 days from the alleged discrimination, unless the time is extended by the Department. The Department is required to make a prompt investigation whenever a compliance review, complaint, or other information coming to its attention indicates a possible failure to comply with this part. If compliance cannot be achieved through voluntary means, the regulations provide procedures for termination of Federal financial assistance following an administrative hearing. The Department may also refer the matter to DOJ to secure compliance through any other means authorized by law. These administrative procedures allow individuals to have their complaints investigated without having to file lawsuits.

Complaints may be filed through the OCR Complaint Portal at *ocrportal.hhs.gov/ocr/smartscreen/main.jsf.* The Department also accepts complaints by email at *OCRcomplaint@hhs.gov* and by mail at Centralized Case Management Operations, U.S. Department of Health and Human Services, 200 Independence Ave. SW, Room 509F, Washington, DC 20201.You can call OCR's toll-free number at (800) 368–1019 or (800) 537–7697 (TDD) to speak with someone who can answer your questions and guide you through the process.

Comment: Observing the urgent need for enforcement, multiple commenters, including several disability rights organizations, recommended that we put in place procedures for oversight, monitoring, and enforcement of the regulation. Others said that there must be prioritization and strengthening of enforcement mechanisms. Several commenters stated that compliance is complaint driven and they cautioned against reliance on complaints alone to enforce the regulations. They noted the difficulty of expecting individuals to file complaints during a very stressful time.

Many commenters expressed concerns that the Department does not have enough investigators for all the complaints. They felt that complaints were being ''pushed aside'' because of other priorities. Several commenters said that OCR needs to be adequately funded and staffed to fully implement and enforce the regulations. One commenter suggested that there be a separate division within the Department dedicated to investigating complaints.

[228] U.S. Dep't of Health & Human Servs., U.S. Dep't of Justice, *Access to Medical Care for Individuals with Mobility Disabilities* (July 2010), *https://www.hhs.gov/sites/default/files/ocr/civilrights/understanding/disability/adamobilityimpairmentsgudiance.pdf.*

[229] *See id.*

[230] 29 U.S.C. 794f.

Response: We appreciate commenters' concerns and recognize the need for strong enforcement mechanisms. As noted above, the Department can initiate proactive compliance reviews on any matter that comes to their attention without the need for a complaint to be filed. The Department has a robust program of performing proactive agency-initiated compliance and an enforcement division dedicated to compliance reviews and complaint investigations with regional offices around the county. We will continue to efficiently address complaints and conduct compliance reviews consistent with the finite resources that we have available.

Comment: We received many comments urging that the complaint process be reformed and streamlined. Several commenters highlighted the need for transparency about the complaint investigation process. A few commenters recommended that individuals should have more than 180 days to file complaints, there should be shorter time frames for responding by the Department, and barriers to accessing the complaint form should be eliminated. Many commenters suggested that resources, including legal assistance, be made available to help individuals in filing complaints. Noting that the Department encourages the use of the on-line complaint form, many commenters expressed concerns about the burden that this places on individuals who may have difficulty using a computer and filling out forms on-line. They said that the technical process should not create a hardship when an individual is already under emotional and mental stress because of perceived discrimination.

A number of commenters urged the Department to reduce the burden of filing complaints and to improve communication with individuals with disabilities during the filing process. Others said that we should provide specific guidance on how individuals and organizations can file complaints, how we will investigate them, and how they will be resolved. One commenter recommended that the regulations permit individuals to file complaints even if they haven't personally experienced discrimination.

Response: We thank the commenters for their suggestions to improve the complaint process. We understand that the complaint procedure can be challenging, and we are always striving to simplify the process and to make it as transparent as possible. Staff are available to assist in the process; however, we cannot provide legal assistance to individuals filing complaints. The OCR website contains information about the process of filing a complaint and what to expect when a complaint is filed. In response to the comment about extending the 180-day time frame for filing complaints, we note that under the existing regulations the Department has discretion to extend the 180-day requirement. In addition, the existing regulations make it clear that anyone can file a complaint of discrimination.

Comment: Many disability rights organizations and others urged the Department to use a cooperative rather than a punitive approach. They emphasized the need for the Department to work collaboratively with recipients to develop corrective action plans. Several asked that we provide recipients with resources and support to help them comply with the law. One commenter suggested that the Department focus on systemic practices while State and local recipients handle individual complaints. Noting that self-policing is a powerful way to promote enforcement, the commenter recommended that large recipients be required to institute internal complaint systems. Several commenters suggested that recipients designate someone to be responsible for ensuring enforcement of the regulation, accepting complaints, and answering questions.

Response: We appreciate commenters' concerns and remain firmly committed to using a cooperative approach. Throughout the investigative process, OCR provides technical assistance and works closely with recipients to help them comply with the law. The vast majority of OCR's complaints are resolved in this cooperative manner and often result in Voluntary Resolution Agreements. The Department's current section 504 regulation at § 84.61 adopts the procedural provisions of title VI of the Civil Rights Act of 1964 for its section 504 regulation. The title VI regulation provides the legal framework for the Department's investigative process, including the obligation to attempt to resolve matters voluntarily and to assist recipients with compliance. 45 CFR 80.6(a); 80.7(d)(1); 80.8(a).

The existing regulations require that recipients designate an individual responsible for ensuring compliance and instituting a grievance procedure. Section 84.7(a) in the existing section 504 rule, which is retained in this final rule, requires recipients with 15 or more employees to designate an employee to coordinate efforts to comply with the part. Section 84.7(b) requires those recipients to adopt grievance procedures that provide for prompt and equitable resolution of complaints.

With regard to the suggestion that the Department only handle statewide cases while State and local recipients handle individual matters, we note that the only agency with authority to enforce section 504 and to investigate section 504 complaints against its recipients is the Department. However, an effective grievance procedure can allow internal resolution of complaints, potentially reducing the number of formal complaints filed with the Department.

Comment: Multiple commenters, including several disability rights organizations, emphasized the urgent need for training and educational materials on the provisions in the rule. Many requested technical assistance and guidance documents to help them understand the requirements. Others asked for financial resources to help them comply.

Response: We appreciate commenters' concerns and understand the importance of providing technical assistance and guidance to support compliance with this rule, and we will continue our practice of providing educational materials, guidance, and technical assistance documents on our website. Commenters' requests for providing increased training on the rule will be taken into consideration. The Department cannot provide financial assistance to recipients to ensure compliance with the part.

Data Collection

Comment: A multitude of commenters, including many disability rights organizations, urged the Department to collect disability data. They recommended a provision in the rule requiring recipients to gather disability data that would allow for equal inclusion of people with disabilities in equity and quality analyses and would contain information as to whether and how individuals received modifications. Others said that there is a need for systematic, accurate, timely, and comprehensive collection, analysis, and public reporting of disability data for demographic purposes.

Response: Section 80.6(b) of the title VI regulations, incorporated into this rule by § 84.98, requires recipients to keep compliance records that must be submitted to the Department as requested including data showing the extent to which individuals with disabilities are beneficiaries of and participants in federally assisted programs. That section permits the Department to obtain any data it needs to determine compliance with this rule

as it performs complaint investigations and compliance reviews. However, obtaining data in this manner is done on a case-by-case basis as needed. There is no requirement that every recipient maintain and submit data to the Department.

We agree that there needs to be better standards and practices in collecting data as this can have a positive impact in reducing disparities. Developing a civil rights data collection scheme can help to ensure that any civil rights data collection yields accurate data that mitigates potential negative impacts and that adequately protects the privacy of individuals. The Department is actively engaged with other agencies within the Department and throughout the Federal Government related to responsible data collection and recognizes the importance of data collection to meet its mission. The value of any data collection requirement will be significantly hampered by misalignment with the data needs of other agencies. For these reasons, the Department has decided to forgo the imposition of a data collection requirement in this rulemaking. We will continue to work with recipients and beneficiaries, and will consider whether an additional data collection requirement is needed in a future rulemaking.

Summary of Regulatory Changes

For the reasons set forth above and considering the comments received, we are finalizing § 84.98 as proposed without modification.

Section 504 Federally Conducted Rule

This rule covers federally assisted programs. In the preamble to the proposed rule, we stated that since section 504 also covers programs and activities conducted by the Department, the Department intends to publish a separate rulemaking to update its federally conducted regulation enacted in 1998 (45 CFR part 85).

Comments: Many commenters, including several disability rights organizations, applauded the Department for issuing the federally assisted regulation, noting that the robust improvements in the proposed rule are welcome and critically important. However, they expressed disappointment that a federally conducted NPRM was not issued at the same time as the federally assisted NPRM. They said that this delay represents a striking omission, and they strongly urged the Department to accelerate publication of the rulemaking so that the essential updates to the section 504 federally assisted regulations can be applied to the Department itself which has a wide range of programs under its purview. Another commenter noted the importance of supporting individuals with disabilities within the Federal Government to ensure equal and full participation in the Federal workforce.

Response: The Department appreciates the comments received. We understand the importance of issuing a section 504 federally conducted rule, and we intend to do so soon. We note that the current section 504 federally conducted regulation remains in effect.[231]

IV. Executive Order 12866 and Related Executive Orders on Regulatory Review

A. Regulatory Impact Analysis Summary

a. Statement of Need

The Department is revising its existing section 504 regulation prohibiting discrimination on the basis of disability in programs and activities receiving Federal financial assistance from the Department. More than 40 years have passed since the Department originally issued regulations implementing section 504, with only limited changes in the decades since. During that time, major legislative and judicial developments have shifted the legal landscape of disability discrimination protections under section 504, including statutory amendments to the Rehabilitation Act, the enactment of the ADA and the ADAAA, the ACA, and Supreme Court and other significant court cases. HHS's section 504 regulation needed to be updated to reflect these developments in the law.

b. Overall Impact

We have examined the impacts of the final rule under Executive Order (E.O.) 12866, as amended by E.O. 14094; E.O. 13563; the Small Business Regulatory Enforcement Fairness Act (also known as the Congressional Review Act, 5 U.S.C. 801 *et seq.*); the Regulatory Flexibility Act (5 U.S.C. 601–612); and the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4). E.O. 12866 and E.O. 13563 direct us to assess all costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity). This final rule is a significant regulatory action under section 3(f)(1) of E.O. 12866, as amended by E.O. 14094.

The Regulatory Flexibility Act requires us to analyze regulatory options that would minimize any significant impact of a rule on small entities. Because the costs of the final rule are small relative to the revenue of recipients, including covered small entities, and because even the smallest affected entities would be unlikely to face a significant impact, we certify that the final rule will not have a significant economic impact on a substantial number of small entities.[232]

The Unfunded Mandates Reform Act of 1995 (section 202(a)) generally requires the Department to prepare a written statement, which includes an assessment of anticipated costs and benefits, before proposing ''any rule that includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more (adjusted annually for inflation) in any one year.'' This final rule is not subject to the Unfunded Mandates Reform Act because it falls under an exception for regulations that establish or enforce any statutory rights that prohibit discrimination on the basis of race, color, religion, sex, national origin, age, handicap, or disability.[233]

The Congressional Review Act (CRA) defines a ''major rule'' as ''any rule that the Administrator of the Office of Information and Regulatory Affairs (OIRA) of the Office of Management and Budget finds has resulted in or is likely to result in—(A) ''an annual effect on the economy of $100,000,000 or more''; (B) ''a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions''; or (C) ''significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic and export markets.'' 5 U.S.C. 804(2). OMB's Office of Information and Regulatory Affairs has determined that this final rule does meet the criteria set forth in 5 U.S.C. 804(2). The Department will comply with the CRA's requirements to inform Congress.

The Background and Overview sections at the beginning of this preamble contain a summary of this final rule and describe the reasons it is needed.

[231] 45 CFR part 85.

[232] *See* discussion in section ''Regulatory Flexibility Act—Small Entity Analysis'' below.

[233] 2 U.S.C. 1503(2).

Below is a summary of the results and methodology from our Regulatory Impact Analysis (RIA). A complete version of this RIA will be available at *https://www.hhs.gov/sites/default/files/sec-504-ria-final-rule-2024.PDF.*

c. Summary of Costs and Benefits

Section 504 has applied to medical care providers that receive Federal financial assistance from the Department for approximately fifty years. The Department issued regulatory language detailing specific requirements for health care providers in 1977.[234] The health care sector in the United States is quite broad, encompassing about 490,000 providers of ambulatory health care services and 3,044 hospitals. It includes 168,459 offices of physicians; 124,384 offices of dentists; 141,853 offices of other health care practitioners; 7,192 medical and diagnostic laboratories; 24,619 home health care service providers; and 19,625 outpatient care centers. Most of these entities receive Federal financial assistance. For example, the Department estimates that approximately 92% of doctors, 43% of dentists, and all hospitals receive Federal financial assistance from the Department and are thus subject to section 504. The Department's section 504 rule applies to this universe of recipients, updating the Department's original regulation and adding new provisions in several areas. This section 504 rule does not apply to health care programs and activities conducted by the Department. Those programs and activities are covered by part 85 of section 504, which covers federally conducted (as opposed to federally assisted) programs or activities.[235] While a majority of the estimated costs associated with this rule concern health care providers, the rule covers all recipients of HHS funding.

The RIA considers the various sections and quantifies several categories of costs that we anticipate recipients may incur. The RIA quantifies benefits people with disabilities are expected to receive due to higher percentages of accessible Medical Diagnostic Equipment (yielding improved health outcomes) at recipients' locations and discusses unquantified significant benefits and costs the final rule is expected to generate that could not be quantified or monetized (due to lack of data or for other methodological reasons). The RIA also quantifies benefits that will result from accessible web content and mobile applications while addressing unquantified benefits the final rule is expected to accrue.

Table 1 below summarizes RIA results with respect to the likely incremental monetized benefits and costs, on an annualized basis. All monetized benefits and costs were estimated using discount rates of 7 and 3 percent. The Final RIA results differ from Preliminary RIA results because some subpart I costs and benefits, which are based on the DOJ web accessibility RIA,[236] have been recalculated to account for changes DOJ has made to its web accessibility RIA. Final RIA results also differ from Preliminary RIA results because the Final RIA results are expressed in 2022 dollars, while the Preliminary RIA results are expressed in 2021 dollars.

TABLE 1—ANNUALIZED VALUE OF MONETIZED BENEFITS AND COSTS UNDER THE FINAL RULE, IN 2022 DOLLARS

[Annualized value of monetized costs and benefits under the final rule]

[In 2022 dollars]

	7-Percent discount rate (in millions)	3-Percent discount rate (in millions)
Monetized Incremental Costs		
Subpart I—Web, Mobile, and Kiosk Accessibility	934.7	916.9
Subpart J—Accessible Medical Equipment	377.4	371.6
§ 84.56—Medical Treatment	14.0	13.6
§ 84.57—Value Assessment Methods	0.1	0.1
§ 84.60—Child Welfare	0.1	0.1
Total Monetized Incremental Costs *	1,326.1	1,302.1
Monetized Incremental Benefits		
Subpart I—Web, Mobile, and Kiosk Accessibility	1,265.6	1,311.8
Subpart J—Accessible Medical Equipment	145.5	145.5
Total Monetized Incremental Benefits *	1,411.1	1,457.3

(* **Note:** Totals may not sum due to rounding. The effects of this rule overlap with the effects of DOJ's final rule under title II of the ADA (89 FR 31320, April 24, 2024); see Summary Table C in the Regulatory Impact Analysis (RIA), which is also reproduced below, for quantified overlapping costs and benefits.)

[234] For example, all recipients have been required to construct new facilities and alter existing facilities in an accessible manner, make changes to ensure program accessibility, provide alternate means of communication for persons who are blind, deaf, have low vision, or are hard of hearing (*e.g.,* sign language interpreters, materials in Braille or on tape), and prohibited from denying or limiting access to their health care programs or from otherwise discriminating against qualified persons with a disability in their health care programs or activities.

[235] 45 CFR part 85.

[236] U.S. Dep't of Justice, Title II Web and Mobile App Access FRIA 04–08–2024, *https://www.ada.gov/assets/pdfs/web-fria.pdf.*

SUMMARY TABLE C—ANNUALIZED VALUE OF MONETIZED BASE COSTS AND BENEFITS EXCLUDING THOSE ASSOCIATED WITH RECIPIENTS THAT ARE PUBLIC ENTITIES COVERED BY DOJ TITLE II WEB ACCESSIBILITY FINAL RULE (89 FR 31320, APRIL 24, 2024) IN 2022 DOLLARS

[Millions]

Subpart I costs and benefits	Costs, 7% discount rate	Costs, 3% discount rate	Benefits, 7% discount rate	Benefits 3% discount rate
(1) All recipients	934.7	916.9	1,265.6	1,311.8
(2) Excluding recipients that are also public entities under title II	384.9	393.2	77.4	84.0

Quantified incremental costs concerning accessible medical equipment under subpart J come from updating policies and procedures, acquiring accessible medical diagnostic equipment (MDE), and ensuring staff are qualified to successfully operate accessible MDE. Quantified incremental costs concerning web, mobile, and kiosk accessibility under subpart I come from reviewing and updating existing web content and mobile apps while ensuring ongoing conformance with listed standards for web content and mobile apps.

Additional costs for provisions under § 84.56, Medical treatment, § 84.57, Value assessment methods, and § 84.60, Child welfare, are calculated based on limited revisions to policies and procedures and training for employees on provisions that largely restate existing obligations and explicitly apply them to specific areas of health and human services. The RIA requested comment on more extensive transition and ongoing costs, but did not receive comments on those costs.

Concerning the provisions to ensure consistency with the ADA, statutory amendments to the Rehabilitation Act, and Supreme Court and other significant court cases, the Department believes that these provisions will likely result in no additional costs to recipients.

Regarding costs that can be monetized, the RIA finds that the final rule would result in annualized costs of $1,302.1 million or $1,326.1 million ($778.4 million or $776.4 million, if limited to costs that do not overlap with DOJ's final web accessibility rule under title II of the ADA), corresponding to a 3% or a 7% discount rate. We separately report a full range of cost estimates of about $1,047.5 million to $1,765.6 million at a 3% discount rate, and a full range of cost estimates of about $1,072.9 million to $1,798.8 million at a 7% discount rate.

For quantified benefits, the RIA quantifies the benefits that people with disabilities are expected to receive due to higher percentages of accessible Medical Diagnostic Equipment (yielding improved health outcomes) at recipients' locations and more accessible web content, mobile apps, and kiosks.

Benefits from web, mobile, and kiosk accessibility and accessible school courses come from time savings and better education outcomes for both people with disabilities and people without disabilities. We conclude that the final rule yields subpart I benefits of $1,311.8 million/year at a 3% discount rate or $1,265.6 million/year at a 7% discount rate ($84.0 million or $77.4 million, if limited to benefits that do not overlap with DOJ's web accessibility final rule).

Subpart J benefits are benefits people with disabilities are expected to receive thanks to higher percentages of accessible MDE yielding improved health outcomes at recipients' locations. We conclude that the final rule yields $145.5 million/year in cancer-associated benefits. We separately report a range of quantifiable cancer-associated benefit estimates of $97.0 million to $193.9 million per year.

Total quantified benefits from subparts I and J provisions are thus estimated to exceed corresponding costs. Total annualized benefits are estimated to be $1,457.3 million at a 3% discount rate and $1,411.1 million at a 7% discount rate ($229.4 million or $222.8 million, if limited to benefits that do not overlap with DOJ's web accessibility final rule).

In addition to these quantified benefit estimates, the RIA includes discussions of potential unquantified benefits under the rule. Generally, the RIA anticipates that the final rule will result in myriad benefits for individuals with disabilities as a result of greater access to necessary health and human service programs and activities as well as limitations to discriminatory actions. Analogously, some costs have been quantified, while for others, the RIA requested comment that would facilitate more thorough estimation, and we received no additional information.

The RIA discusses both quantitatively and qualitatively the regulatory alternatives the Department considered in an attempt to achieve the same statutory and regulatory goals while imposing lower costs on society.

Regulatory Flexibility Act—Small Entity Analysis

The Department examined the economic implications of this final rule as required by the Regulatory Flexibility Act. This analysis, as well as other sections in the Regulatory Impact Analysis, serves as the Regulatory Flexibility Analysis, as required under the Regulatory Flexibility Act.

The Department deems that a rule has a significant economic impact on a substantial number of small entities whenever the rule generates incremental cost representing more than 3% of revenue for 5% or more of small recipients.[237]

The U.S. Small Business Administration (SBA) maintains a Table of Small Business Size Standards Matched to North American Industry Classification System Codes (NAICS).[238] Because the RIA uses 2019 counts of firms, for consistency, we have used SBA yearly revenues thresholds for 2019, which for recipients ranged

[237] HHS uses as its measure of significant economic impact on a substantial number of small entities a change in revenues of more than 3% for 5% or more of affected small entities.'' 81 FR 31463 (May 18, 2016). *See also* 87 FR 47906 (Aug. 4, 2022) (''The Department generally considers a rule to have a significant impact on a substantial number of small entities if it has at least a 3% impact on revenue on at least 5% of small entities'').

[238] The most current version became effective on October 1, 2022. *See* U.S. Small Bus. Admin., Table of Size Standards, (last updated Oct. 1, 2022), *https://www.sba.gov/document/support-table-size-standards.* In our analyses, which pertain to 2019, we used the version effective in the 2019 calendar year. We note that CEs' distribution by SBA size—namely, the fraction of CEs that are small by SBA standards—did not change in any meaningful way in the past decades.

between $8 million [239] and $41.5 million.[240]

As reported in the RIA, 97.4% of all firms in the Health Care and Social Assistance sector (NAICS 62) are small. With the exception of Hospitals (Subsector 622), at least 9 out 10 of all recipients within each Health Care and Social Assistance NAICS code are small.

Most firms—98.3%—in the Pharmacies and Drug Stores (NAICS 446110) group are small as well. About 60% of Direct Health and Medical Insurance Carriers (NAICS 524114) are small. About 60% of Colleges, Universities, and Professional Schools (NAICS 611310) are small. Hence, almost all non-government recipients (*i.e.,* private firms) under the scope of the final rule are small businesses. Moreover, the fraction of total small firms in each NAICS code that falls in the smallest size group (fewer than 5 employees) is greater than 5% for all relevant NAICS codes. Because most non-government recipients under the scope of the final rule are small businesses, it is sufficient to investigate the impact of the final rule on the average recipient in the smallest size group to determine whether the final rule may generate a change in revenues of more than 3%. We need to determine whether the average firm in the smallest size group will incur incremental cost greater than 3%.

Below we discuss the two reasons for our conclusion that firms in the smallest groups will not experience a 3% reduction in revenues. Hence, we certify that the final rule will not have a significant economic impact on a substantial number of small entities.

As for the first reason, we note that, with the exception of a handful of HMO Medical Centers (NAICS 621491) and about 24,500 Child Day Care Services (NAICS 624410) firms, the yearly average revenue (in 2022 dollars) for a recipient belonging to the smallest size group—for each 6-digit NAICS code considered separately—is $190,000 or more. Three percent of this sum is about $5,700 (2022 dollars), which, based on our review of data on prices for MDE as well as incremental costs for ensuring qualified staff, we deem is an amount sufficient to finance purchase of the limited set of inexpensive MDE the smallest entities typically need as well as to ensure qualified staff.

Considering the smallest recipient groups among each of the 6-digit NAICS groups that private recipients belong to, the typical yearly average revenue is about $354,000. That represents the median of the average revenues across all relevant 6-digit NAICS codes. Podiatrists' offices' average yearly revenue is at the median, but general hospitals have the highest average yearly revenue among the relevant NAICS codes at $20 million, and Child Day Care Services have the lowest average yearly revenue among the relevant NAICS codes at $116,000. Thus, in many cases the 3% revenue threshold is about $10,000. Costs of the final rule are mostly proportional to the size of the recipient, and typical recipients in the smallest size group (fewer than 5 employees) are not expected to incur $10,000 incremental costs.[241]

In addition, we estimate that the obligation to ensure that web content and mobile applications for the Department's recipients that are small providers (those with fewer than fifteen employees) will be less than 3% of their revenues. We note that the vast majority of the Department's recipients are small providers and estimate that most of these small providers (approximately 85.9%) have websites. The websites of these small providers are typically one domain with up to a few thousand pages and limited visitors per month. Thus, the Department estimates that for a cost of approximately $440 per year small recipients will be able to ensure that their websites can be made accessible and kept accessible each year.

Comment: Some commenters expressed concern that the requirements of subpart I would lead to significant costs for recipients. One commenter in particular stated that it reviewed the price estimates of a firm that offers services to make web content ''ADA compliant'' and believed that the costs for reviewing existing web content for compliance and remediating web content for compliance could be more than $23,500 with additional monthly expenses.[242]

Response: In the RIA, the Department sampled several software companies' price lists for products and services designed to make websites accessible in order to estimate average compliance costs for recipients of various sizes. Based on that sampling, the Department estimates the average annual compliance costs for the 113,295 larger recipients to be $2,500 per year. Using that same methodology, the Department estimates the annual compliance costs for the 339,789 smaller recipients (comprising offices of physicians, dentists, and other health practitioners) will be much lower given that the smaller entities' websites are expected to be less complex and include fewer pages. The Department's RIA estimates that the 85.9% of these smaller entities that have websites will spend an average of $440/year to ensure their pages are accessible. While there will be instances where a recipient incurs costs above the Department's estimated annual costs, those will likely be incurred by large recipients, such as hospitals with multiple locations, that use web content and mobile apps extensively and already devote significant resources to creating and maintaining web content and mobile apps. In rare instances where a small recipient has a significant online presence that would require a large percentage of its resources to review and remediate, the recipient may argue that full compliance with subpart I would amount to an undue burden under § 84.88.

We stress that the final rule includes exceptions meant to ease the burden on small firms and does not require entities to take any action that would result in a fundamental alteration in the nature of a program or activity or cause the entities to incur undue financial and administrative burdens.

Executive Order 13132: Federalism

As required by E.O. 13132 on Federalism, the Department has examined the effects of provisions in the final regulation on the relationship between the Federal Government and the States. The Department has concluded that the final regulation has federalism implications but notes that State law will continue to govern unless displaced under standard principles of preemption.

[239] The $8 million yearly 2019 revenue threshold applies to several NAICS, including 621340, Offices of Physical, Occupational and Speech Therapists and Audiologists, and 624410, Child Day Care Services. These $8 million yearly 2019 revenue thresholds have been increased for three NAICS: 621340, Offices of Physical, Occupational and Speech Therapists and Audiologists (to $11 million); 621399, Offices of All Other Miscellaneous Health Practitioners (to $9 million) and 624410, Child Day Care Services (to 8.5 million).

[240] The $41.5 million yearly 2019 revenue threshold applies to Hospitals (NAICS 622), Direct Health and Medical Insurance Carriers (NAICS 524114) and Kidney Dialysis Centers (NAICS 621492). These thresholds have not changed in SBA's October 1, 2022, update. The $41.5 million yearly revenue threshold remains the highest value for recipients considered in our analyses.

[241] See full Regulatory Impact Analysis for tables and calculations.

[242] *See* Skynet Technologies, *How much does it cost to make a website ADA compliant? What are the factors that impact the cost?, https://www.skynettechnologies.com/blog/cost-to-make-website-ada-compliant* (last visited Dec. 15, 2023).

The regulation attempts to balance State autonomy with the necessity to create a Federal benchmark that will provide a uniform level of nondiscrimination protection across the country. It is recognized that the States generally have laws that relate to nondiscrimination against individuals on a variety of bases. Such State laws continue to be enforceable, unless they prevent application of the final rule. The rule explicitly provides that it is not to be construed to supersede State or local laws that provide additional protections against discrimination on any basis articulated under the regulation. Provisions of State law relating to nondiscrimination that are ''more stringent'' than the Federal regulatory requirements or implementation specifications will continue to be enforceable. Section 3(b) of E.O. 13132 recognizes that national action limiting the policymaking discretion of States will be imposed only where there is constitutional and statutory authority for the action and the national activity is appropriate considering the presence of a problem of national significance. Discrimination issues in relation to health care are of national concern by virtue of the scope of interstate health commerce.

Section 4(a) of E.O. 13132 expressly contemplates preemption when there is a conflict between exercising State and Federal authority under a Federal statute. Section 4(b) of the Executive order authorizes preemption of State law in the Federal rulemaking context when ''the exercise of State authority directly conflicts with the exercise of Federal authority under the Federal statute.'' The approach in this regulation is consistent with these standards in the Executive order in superseding State authority only when such authority is inconsistent with standards established pursuant to the grant of Federal authority under the statute.

We received comments, including from States, that the Department did not consult with States in violation of E.O. 13132, particularly with respect to the integration provision's prohibition of failure to provide community-based services that results in serious risk of institutionalization. As explained above in the preamble discussion of the integration provision at § 84.76, application of the integration mandate's protection to individuals ''at serious risk of institutionalization'' in the absence of community-based services is a well-established principle adopted by six circuits following *Olmstead,* beginning in 2003 with the decision in *Fisher* v. *Oklahoma Health Care Authority.*[243] Given that this rule creates no new obligations to State and local governments, all of which have the existing responsibilities clarified in this rule under section 504 and analogous regulatory provisions in title II, this rule does not impose any new preemption of State law. Moreover, although the proposed rule addresses circumstances not previously covered specifically in the existing rule, those provisions also do not create new obligations for State and local governments, or other recipients of Federal financial assistance, but instead explicate longstanding requirements in the existing section 504 regulations that prohibit recipients from providing services to qualified persons with disabilities in a manner that does not provide equal opportunities for such persons to gain the same benefits. In addition, a number of State and local governments and State agencies participated in the process by submitting comments in response to NPRM.

Section 6(b) of E.O. 13132 includes some qualitative discussion of substantial direct compliance costs that State and local governments would incur as a result of a final regulation. We have considered the cost burden that this rule imposes on State and local government recipients and estimate State and local government annualized costs will be about $563.6 million per year (2022 dollars) at a 3% discount rate and $589.8 million at a 7% discount rate.

These costs represent the sum of costs for compliance with all provisions applying to State and local governments, namely those for subpart I (about 40% of costs for all recipients, *i.e.,* public and private entities altogether), subpart J (about 10% of costs for all recipients), § 84.56—Medical treatment (about 10% of costs for all recipients), 100% of costs for § 84.57—Value assessment methods (only public entities—Medicaid agencies—bear these costs), and § 84.60—Child welfare (about 4% of costs of all recipients).

In addition, the Department is aware that DOJ published the final Regulatory Impact Analysis [244] to accompany its rule finalizing requirements for public entities covered by title II of the ADA and that its requirements are consistent with this Department's subpart I.[245] DOJ examined the costs of its proposal for all public entities covered by title II and stated that the rule will not be unduly burdensome or costly for public entities. Because this Department's rule is consistent with the DOJ final rule (89 FR 31320, April 24, 2024), we believe that the DOJ analysis provides further support for our belief that subpart I will not be unduly burdensome or costly for the Department's recipients that are public entities.

Paperwork Reduction Act

This final rule contains information collection requirements that are subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (PRA).[246] Under the PRA, agencies are required to submit to OMB for review and approval any reporting or record-keeping requirements inherent in a proposed or final rule and are required to publish such proposed requirements for public comment. In order to evaluate whether an information collection should be approved by OMB, the PRA requires that the Department solicits comment on the following issues:

1. Whether the information collection is necessary and useful to carry out the proper functions of the agency;

2. The accuracy of the agency's estimate of the information collection burden;

3. The quality, utility, and clarity of the information to be collected; and

4. Recommendations to minimize the information collection burden on the affected public, including automated collection techniques.[247]

The PRA requires consideration of the time, effort, and financial resources necessary to meet the information collection requirements referenced in this section. The Department previously published a notice of a proposed data collection on September 14, 2023, at 88 FR 63392–6351, as part of an NPRM entitled ''Discrimination on the Basis of Disability in Health and Human Service Programs or Activities'' (RIN 0945–AA15), to invite public comment. OCR solicited comment on the issues listed above and estimated the annual burden of the information collection request (ICR) to be 256,763 hours. The new information collection is evaluated under OMB Control Number 0945–0013.

OCR did not receive comments related to the previous notice.

The notice requirement outlined in § 84.8 implicates the third-party disclosure provisions of the PRA implementing regulations, which compels an agency to request comment

[243] 335 F.3d 175 (10th Cir. 2003).

[244] U.S. Dep't of Justice, Title II Web and Mobile App Access FRIA 04–08–2024, *https://www.ada.gov/assets/pdfs/web-fria.pdf.*

[246] 44 U.S.C. 3501–3520.

[247] 44 U.S.C. 3506(c)(2)(A).

and submit for OMB review any agency regulation that requires an individual ''to obtain or compile information for the purpose of disclosure to members of the public or the public at large, through posting, notification, labeling or similar disclosure. . . .''

Table 6 of the Regulatory Impact Analysis reports that there are about 453,084 recipients covered by this rulemaking. We estimate the burden for responding to the § 84.8 notice requirement assuming a single response per recipient, and that administrative or clerical support personnel will spend 34 minutes (0.5667 of an hour) to respond. The estimated total number of hours to respond is 256,763 (0.5667 × 453,084).

Unfunded Mandates Reform Act

Section 4(2) of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1503(2), excludes from coverage under that Act any proposed or final Federal regulation that ''establishes or enforces any statutory rights that prohibit discrimination on the basis of race, color, religion, sex, national origin, age, handicap, or disability.'' Accordingly, this rulemaking is not subject to the provisions of the UMRA.

The Department received comment from some State officials arguing that the integration provision in § 84.76 Integration is subject to the UMRA. For the reasons discussed in the preamble for § 84.76, the Department declines this interpretation and restates that the rule in its entirety is exempted from the UMRA as a rule that enforces nondiscrimination on the basis of disability.

National Technology Transfer and Advancement Act of 1995

The National Technology Transfer and Advancement Act of 1995 (NTTAA) directs that, as a general matter, all Federal agencies and departments shall use technical standards that are developed or adopted by voluntary consensus standards bodies, which are private, generally nonprofit organizations that develop technical standards or specifications using well-defined procedures that require openness, balanced participation among affected interests and groups, fairness and due process, and an opportunity for appeal, as a means to carry out policy objectives or activities.[248]

The Department sought public comment in the NPRM on the accessibility standards for accessible medical diagnostic equipment and whether there are any other standards for accessible medical diagnostic equipment that the Department should consider. We received no significant public comment in response to our question requesting suggestions of alternative standards to apply to MDE. We also sought comment on the selection of WCAG 2.1 AA to coordinate the implementation and enforcement by Executive agencies of section 504 of the Rehabilitation Act of 1973, as amended (29 U.S.C. 794). Executive Order 12250 at section 1–2(c), 45 FR 72995 (Nov. 2, 1980). E.O. 12250 does not apply to the 504 provisions relating to equal employment, which are reviewed and coordinated by the Equal Employment Opportunity Commission.[249] The Attorney General has delegated the E.O. 12250 functions to the Assistant Attorney General for the Civil Rights Division for purposes of reviewing and approving proposed and final rules.[250]

The proposed rule was reviewed and approved by the Assistant Attorney General, and this final rule was also reviewed and approved by the Assistant Attorney General.

Incorporation by Reference

Through this rule, the Department is adopting the internationally recognized accessibility standard for web access, WCAG 2.1, published in June 2018, as the technical standard for web and mobile app accessibility under section 504. WCAG 2.1, published by W3C WAI, specifies success criteria and requirements that make web content more accessible to all users, including individuals with disabilities. The Department incorporates WCAG 2.1 by reference into this rule, instead of restating all of its requirements verbatim. To the extent there are distinctions between WCAG 2.1 and the standards articulated in part 84, the standards articulated in part 84 prevail.

The Department notes that when W3C publishes new versions of WCAG, those versions will not be automatically incorporated into this rule. Federal agencies do not incorporate by reference into published regulations future versions of standards developed by bodies like W3C. Federal agencies are required to identify the particular version of a standard incorporated by reference in a regulation.[251] When an updated version of a standard is published, an agency must revise its regulation if it seeks to incorporate any of the new material.

WCAG 2.1 Level AA is reasonably available to interested parties. Free copies of WCAG 2.1 Level AA are available online on W3C's website at *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F.* In addition, a copy of WCAG 2.1 Level AA is also available for inspection by appointment at Office for Civil Rights, U.S. Department of Health and Human Services, 200 Independence Ave. SW, Room 509F, HHH Building, Washington, DC 20201.

List of Subjects in 45 CFR Part 84

Adoption and foster care, Civil rights, Childcare, Child welfare, Colleges and universities, Communications, Disabled, Discrimination, Emergency medical services, Equal access to justice, Federal financial assistance, Grant programs, Grant programs—health, Grant programs—social programs, Health, Health care, Health care access, Health facilities, Health programs and activities, Incorporation by reference, Individuals with disabilities, Integration, Long term care, Medical care, Medical equipment, Medical facilities, Nondiscrimination, Public health.

For the reasons set forth in the preamble, the Department of Health and Human Services amends 45 CFR part 84 as follows:

TITLE 45—Public Welfare

PART 84—NONDISCRIMINATION ON THE BASIS OF DISABILITY IN PROGRAMS OR ACTIVITIES RECEIVING FEDERAL FINANCIAL ASSISTANCE

■ 1. The authority citation for part 84 is revised to read as follows:

Authority: 29 U.S.C. 794.

Subpart G also issued under 21 U.S.C. 1174; 42 U.S.C. 4581.

■ 2. Revise the heading for part 84 to read as set forth above.

Subpart A—General Provisions

■ 3. Revise § 84.1 to read as follows:

§ 84.1 Purpose and broad coverage.

(a) *Purpose.* The purpose of this part is to implement section 504 of the Rehabilitation Act of 1973, as amended, which prohibits discrimination on the basis of disability in any program or activity receiving Federal financial assistance.

(b) *Broad coverage.* The definition of ''disability'' in this part shall be

[248] Public Law 104–113, section 12(d)(1) (15 U.S.C. 272 Note).

[249] *See* E.O. 12250 (DOJ Coordination authority) at 1–503 and E.O. 12067 (EEOC Coordination authority).

[250] 28 CFR 0.51.

[251] *See, e.g.,* 1 CFR 51.1(f) (''Incorporation by reference of a publication is limited to the edition of the publication that is approved [by the Office of the Federal Register]. Future amendments or revisions of the publication are not included.'').

construed broadly in favor of expansive coverage to the maximum extent permitted by the terms of section 504. The primary object of attention in cases brought under section 504 should be whether entities receiving Federal financial assistance have complied with their obligations and whether discrimination has occurred, not whether the individual meets the definition of ''disability.'' The question of whether an individual meets the definition of ''disability'' under this part should not demand extensive analysis.

■ 4. Revise § 84.2 to read as follows:

§ 84.2 Application.

(a) This part applies to each recipient of Federal financial assistance from the Department and to the recipient's programs or activities that involve individuals with disabilities in the United States. This part does not apply to the recipient's programs or activities outside the United States that do not involve individuals with disabilities in the United States.

(b) The requirements of this part do not apply to the ultimate beneficiaries of any program or activity operated by a recipient of Federal financial assistance.

(c) Any provision of this part held to be invalid or unenforceable by its terms, or as applied to any person or circumstance, shall be construed so as to continue to give maximum effect to the provision permitted by law, unless such holding shall be one of utter invalidity or unenforceability, in which event the provision shall be severable from this part and shall not affect the remainder thereof or the application of the provision to other persons not similarly situated or to other dissimilar circumstances.

§ 84.10 [Removed]

■ 5. Remove § 84.10.

§ 84.3 [Redesignated as § 84.10]

■ 6. Redesignate § 84.3 as § 84.10.

■ 7. Add new § 84.3 to read as follows:

§ 84.3 Relationship to other laws.

This part does not invalidate or limit the remedies, rights, and procedures of any other Federal laws, or State or local laws (including State common law) that provide greater or equal protection for the rights of individuals with disabilities, or individuals associated with them.

■ 8. Revise § 84.4 to read as follows:

§ 84.4 Disability.

(a) *Definition*—(1) *Disability.* *Disability* means, with respect to an individual:

(i) A physical or mental impairment that substantially limits one or more of the major life activities of such individual;

(ii) A record of such an impairment; or

(iii) Being regarded as having such an impairment as described in paragraph (f) of this section.

(2) *Rules of construction.* (i) The definition of ''disability'' shall be construed broadly in favor of expansive coverage, to the maximum extent permitted by the terms of section 504.

(ii) An individual may establish coverage under any one or more of the three prongs of the definition of ''disability'' in paragraph (a)(1) of this section, the ''actual disability'' prong in paragraph (a)(1)(i) of this section, the ''record of'' prong in paragraph (a)(1)(ii) of this section, or the ''regarded as'' prong in paragraph (a)(1)(iii) of this section.

(iii) Where an individual is not challenging a recipient's failure to provide reasonable modifications, it is generally unnecessary to proceed under the ''actual disability'' (paragraph (a)(1)(i) of this section) or ''record of'' (paragraph (a)(1)(ii) of this section) prongs, which require a showing of an impairment that substantially limits a major life activity or a record of such an impairment. In these cases, the evaluation of coverage can be made solely under the ''regarded as'' (this paragraph (a)(1)(iii)) prong of the definition of disability, which does not require a showing of an impairment that substantially limits a major life activity or a record of such an impairment. An individual may choose, however, to proceed under the ''actual disability'' or ''record of'' prong regardless of whether the individual is challenging a recipient's failure to provide reasonable modifications.

(b) *Physical or mental impairment*—(1)(i) *Physical or mental impairment* is defined as any physiological disorder or condition, cosmetic disfigurement, or anatomical loss affecting one or more body systems, such as: neurological, musculoskeletal, special sense organs, respiratory (including speech organs), cardiovascular, reproductive, digestive, genitourinary, immune, circulatory, hemic, lymphatic, skin, and endocrine; or

(ii) Any mental or psychological disorder such as intellectual disability, organic brain syndrome, mental health condition, and specific learning disability.

(2) *Physical or mental impairment* includes, but is not limited to, contagious and noncontagious diseases and conditions such as the following: orthopedic, visual, speech and hearing impairments, and cerebral palsy, epilepsy, muscular dystrophy, multiple sclerosis, cancer, heart disease, diabetes, intellectual disability, mental health condition, dyslexia and other specific learning disabilities, Attention Deficit Hyperactivity Disorder, Human Immunodeficiency Virus infection (whether symptomatic or asymptomatic), tuberculosis, substance use disorder, alcohol use disorder, and long COVID.

(3) *Physical or mental impairment* does not include homosexuality or bisexuality.

(c) *Major life activities*—(1) *Definition.* Major life activities include, but are not limited to:

(i) Caring for oneself, performing manual tasks, seeing, hearing, eating, sleeping, walking, standing, sitting, reaching, lifting, bending, speaking, breathing, learning, reading, concentrating, thinking, writing, communicating, interacting with others, and working; and

(ii) The operation of a major bodily function, such as the functions of the immune system, special sense organs and skin, normal cell growth, and digestive, genitourinary, bowel, bladder, neurological, brain, respiratory, circulatory, cardiovascular, endocrine, hemic, lymphatic, musculoskeletal, and reproductive systems. The operation of a major bodily function includes the operation of an individual organ within a body system.

(2) *Rules of construction.* (i) In determining whether an impairment substantially limits a major life activity, the term major shall not be interpreted strictly to create a demanding standard.

(ii) Whether an activity is a major life activity is not determined by reference to whether it is of central importance to daily life.

(d) *Substantially limits*—(1) *Rules of construction.* The following rules of construction apply when determining whether an impairment substantially limits an individual in a major life activity.

(i) The term ''substantially limits'' shall be construed broadly in favor of expansive coverage, to the maximum extent permitted by the terms of section 504. ''Substantially limits'' is not meant to be a demanding standard.

(ii) The primary object of attention in cases brought under section 504 should be whether recipients have complied with their obligations and whether discrimination has occurred, not the extent to which an individual's impairment substantially limits a major life activity. Accordingly, the threshold issue of whether an impairment

substantially limits a major life activity should not demand extensive analysis.

(iii) An impairment that substantially limits one major life activity does not need to limit other major life activities to be considered a substantially limiting impairment.

(iv) An impairment that is episodic or in remission is a disability if it would substantially limit a major life activity when active.

(v) An impairment is a disability within the meaning of this part if it substantially limits the ability of an individual to perform a major life activity as compared to most people in the general population. An impairment does not need to prevent, or significantly or severely restrict, the individual from performing a major life activity to be considered substantially limiting. Nonetheless, not every impairment will constitute a disability within the meaning of this section.

(vi) The determination of whether an impairment substantially limits a major life activity requires an individualized assessment. However, in making this assessment, the term ''substantially limits'' shall be interpreted and applied to require a degree of functional limitation that is lower than the standard for substantially limits applied prior to the ADA Amendments Act of 2008 (ADAAA).

(vii) The comparison of an individual's performance of a major life activity to the performance of the same major life activity by most people in the general population usually will not require scientific, medical, or statistical evidence. Nothing in this paragraph (d)(1) is intended, however, to prohibit or limit the presentation of scientific, medical, or statistical evidence in making such a comparison where appropriate.

(viii) The determination of whether an impairment substantially limits a major life activity shall be made without regard to the ameliorative effects of mitigating measures. However, the ameliorative effects of ordinary eyeglasses or contact lenses shall be considered in determining whether an impairment substantially limits a major life activity. Ordinary eyeglasses or contact lenses are lenses that are intended to fully correct visual acuity or to eliminate refractive error.

(ix) The six-month ''transitory'' part of the ''transitory and minor'' exception in paragraph (f)(2) of this section does not apply to the ''actual disability'' (paragraph (a)(1)(i) of this section) or ''record of'' (paragraph (a)(1)(ii) of this section) prongs of the definition of ''disability.'' The effects of an impairment lasting or expected to last less than six months can be substantially limiting within the meaning of this section for establishing an actual disability or a record of a disability.

(2) *Predictable assessments.* (i) The principles set forth in the rules of construction in this section are intended to provide for generous coverage and application of section 504's prohibition on discrimination through a framework that is predictable, consistent, and workable for all individuals and entities with rights and responsibilities under section 504.

(ii) Applying the principles in this section, the individualized assessment of some types of impairments as set forth in paragraph (d)(2)(iii) of this section will, in virtually all cases, result in a determination of coverage under paragraph (a)(1)(i) of this section (the ''actual disability'' prong) or paragraph (a)(1)(ii) of this section (the ''record of'' prong). Given their inherent nature, these types of impairments will, as a factual matter, virtually always be found to impose a substantial limitation on a major life activity. Therefore, with respect to these types of impairments, the necessary individualized assessment should be particularly simple and straightforward.

(iii) For example, applying the principles of this section it should easily be concluded that the types of impairments set forth in paragraphs (d)(2)(iii)(A) through (K) of this section will, at a minimum, substantially limit the major life activities indicated. The types of impairments described in this paragraph (d)(2) may substantially limit additional major life activities (including major bodily functions) not explicitly listed in paragraphs (d)(2)(iii)(A) through (K).

(A) Deafness substantially limits hearing;

(B) Blindness substantially limits seeing;

(C) Intellectual disability substantially limits brain function;

(D) Partially or completely missing limbs or mobility impairments requiring the use of a wheelchair substantially limit musculoskeletal function;

(E) Autism Spectrum Disorder substantially limits brain function;

(F) Cancer substantially limits normal cell growth;

(G) Cerebral palsy substantially limits brain function;

(H) Diabetes substantially limits endocrine function;

(I) Epilepsy, muscular dystrophy, and multiple sclerosis each substantially limits neurological function;

(J) Human Immunodeficiency Virus (HIV) infection substantially limits immune function; and

(K) Major depressive disorder, bipolar disorder, post-traumatic stress disorder, traumatic brain injury, obsessive compulsive disorder, and schizophrenia each substantially limits brain function.

(3) *Condition, manner, or duration.* (i) At all times taking into account the principles set forth in the rules of construction in this section, in determining whether an individual is substantially limited in a major life activity, it may be useful in appropriate cases to consider, as compared to most people in the general population, the conditions under which the individual performs the major life activity; the manner in which the individual performs the major life activity; or the duration of time it takes the individual to perform the major life activity, or for which the individual can perform the major life activity.

(ii) Consideration of facts such as condition, manner, or duration may include, among other things, consideration of the difficulty, effort or time required to perform a major life activity; pain experienced when performing a major life activity; the length of time a major life activity can be performed; or the way an impairment affects the operation of a major bodily function. In addition, the non-ameliorative effects of mitigating measures, such as negative side effects of medication or burdens associated with following a particular treatment regimen, may be considered when determining whether an individual's impairment substantially limits a major life activity.

(iii) In determining whether an individual has a disability under the ''actual disability'' (paragraph (a)(1)(i) of this section) or ''record of'' (paragraph (a)(1)(ii) of this section) prongs of the definition of ''disability,'' the focus is on how a major life activity is substantially limited, and not on what outcomes an individual can achieve. For example, someone with a learning disability may achieve a high level of academic success, but may nevertheless be substantially limited in one or more major life activities, including, but not limited to, reading, writing, speaking, or learning because of the additional time or effort he or she must spend to read, write, speak, or learn compared to most people in the general population.

(iv) Given the rules of construction set forth in this section, it may often be unnecessary to conduct an analysis involving most or all of the facts related to condition, manner, or duration. This is particularly true with respect to

impairments such as those described in paragraph (d)(2)(iii) of this section, which by their inherent nature should be easily found to impose a substantial limitation on a major life activity, and for which the individualized assessment should be particularly simple and straightforward.

(4) *Mitigating measures.* Mitigating measures include, but are not limited to:

(i) Medication, medical supplies, equipment, appliances, low-vision devices (defined as devices that magnify, enhance, or otherwise augment a visual image, but not including ordinary eyeglasses or contact lenses), prosthetics including limbs and devices, hearing aid(s) and cochlear implant(s) or other implantable hearing devices, mobility devices, and oxygen therapy equipment and supplies;

(ii) Use of assistive technology;

(iii) Reasonable modifications or auxiliary aids or services as defined in this part;

(iv) Learned behavioral or adaptive neurological modifications; or

(v) Psychotherapy, behavioral therapy, or physical therapy.

(e) *Has a record of such an impairment*—(1) *General.* An individual has a record of such an impairment if the individual has a history of, or has been misclassified as having, a mental or physical impairment that substantially limits one or more major life activities.

(2) *Broad construction.* Whether an individual has a record of an impairment that substantially limited a major life activity shall be construed broadly to the maximum extent permitted by section 504 and should not demand extensive analysis. An individual will be considered to fall within the prong in this paragraph (e) of the definition of ''disability'' if the individual has a history of an impairment that substantially limited one or more major life activities when compared to most people in the general population or was misclassified as having had such an impairment. In determining whether an impairment substantially limited a major life activity, the principles articulated in paragraph (d)(1) of this section apply.

(3) *Reasonable modification.* An individual with a record of a substantially limiting impairment may be entitled to a reasonable modification if needed and related to the past disability.

(f) *Is regarded as having such an impairment.* The following principles apply under the ''regarded'' as prong of the definition of ''disability'' in paragraph (a)(1)(iii) of this section:

(1) Except as set forth in paragraph (f)(2) of this section, an individual is ''regarded as having such an impairment'' if the individual is subjected to a prohibited action because of an actual or perceived physical or mental impairment, whether or not that impairment substantially limits, or is perceived to substantially limit, a major life activity, even if the recipient asserts, or may or does ultimately establish, a defense to the action prohibited by section 504.

(2) An individual is not ''regarded as having such an impairment'' if the recipient demonstrates that the impairment is, objectively, both ''transitory'' and ''minor.'' A recipient may not defeat ''regarded as'' coverage of an individual simply by demonstrating that it subjectively believed the impairment was transitory and minor; rather, the recipient must demonstrate that the impairment is (in the case of an actual impairment) or would be (in the case of a perceived impairment), objectively, both ''transitory'' and ''minor.'' For purposes of this section, ''transitory'' is defined as lasting or expected to last six months or less.

(3) Establishing that an individual is ''regarded as having such an impairment'' does not, by itself, establish liability. Liability is established under section 504 only when an individual proves that a recipient discriminated on the basis of disability within the meaning of section 504.

(g) *Exclusions.* The term ''disability'' does not include the terms set forth at 29 U.S.C. 705(20)(F).

§ 84.6 [Amended]

■ 9. Amend § 84.6 by:

■ a. Removing the word ''handicap'' and adding in its place the word ''disability'' in paragraphs (a)(1) and (2); and

■ b. Removing the words ''handicapped persons'' and adding in their place the words ''persons with disabilities'' wherever they occur in paragraphs (a)(3), (b), and (c).

■ 10. Revise § 84.8 to read as follows:

§ 84.8 Notice.

A recipient shall make available to employees, applicants, participants, beneficiaries, and other interested persons information regarding the provisions of this part and its applicability to the programs or activities of the recipient, and make such information available to them in such manner as the head of the recipient or their designee finds necessary to apprise such persons of the protections against discrimination assured them by section 504 and this part.

■ 11. Revise and republish newly redesignated § 84.10 to read as follows:

§ 84.10 Definitions.

As used in this part, the term:

2004 ADA Accessibility Guidelines (ADAAG) means the requirements set forth in appendices B and D to 36 CFR part 1191 (2009).

2010 Standards means the 2010 ADA Standards for Accessible Design, which consist of the 2004 ADAAG and the requirements contained in 28 CFR 35.151.

ADA means the Americans with Disabilities Act (Pub. L. 101–336, 104 Stat. 327, 42 U.S.C. 12101–12213 and 47 U.S.C. 225 and 611), including changes made by the ADA Amendments Act of 2008 (Pub. L. 110–325), which became effective on January 1, 2009.

Applicant means one who submits an application, request, or plan required to be approved by the designated Department official or by a primary recipient, as a condition of eligibility for Federal financial assistance.

Architectural Barriers Act means the Architectural Barriers Act (42 U.S.C. 4151–4157), including the Architectural Barriers Act Accessibility Standards at 41 CFR 102–76.60 through 102–76.95.

Archived web content means web content that—

(1) Was created before the date the recipient is required to comply with § 84.84, reproduces paper documents created before the date the recipient is required to comply with § 84.84, or reproduces the contents of other physical media created before the date the recipient is required to comply with § 84.84;

(2) Is retained exclusively for reference, research, or recordkeeping;

(3) Is not altered or updated after the date of archiving; and

(4) Is organized and stored in a dedicated area or areas clearly identified as being archived.

Auxiliary aids and services include:

(1) Qualified interpreters on-site or through video remote interpreting (VRI) services; notetakers; real-time computer-aided transcription services; written materials; exchange of written notes; telephone handset amplifiers; assistive listening devices; assistive listening systems; telephones compatible with hearing aids; closed caption decoders; open and closed captioning, including real-time captioning; voice, text, and video-based telecommunications products and systems, including text telephones (TTYs), videophones, and captioned telephones, or equally effective telecommunications devices;

videotext displays; accessible electronic and information technology; or other effective methods of making aurally delivered information available to individuals who are deaf or hard of hearing;

(2) Qualified readers; taped texts; audio recordings; Braille materials and displays; screen reader software; magnification software; optical readers; secondary auditory programs (SAP); large print materials; accessible electronic and information technology; or other effective methods of making visually delivered materials available to individuals who are blind or have low vision;

(3) Acquisition or modification of equipment or devices; and

(4) Other similar services and actions.

Companion means a family member, friend, or associate of an individual seeking access to a program or activity of a recipient, who, along with such individual, is an appropriate person with whom the recipient should communicate.

Conventional electronic documents means web content or content in mobile apps that is in the following electronic file formats: portable document formats (PDF), word processor file formats, presentation file formats, and spreadsheet file formats.

Current illegal use of drugs means illegal use of drugs that occurred recently enough to justify a reasonable belief that a person's drug use is current or that continuing use is a real and ongoing problem.

Department means the Department of Health and Human Services.

Direct threat means:

(1) Except as provided in paragraph (2) of this definition, a significant risk to the health or safety of others that cannot be eliminated by a modification of policies, practices, or procedures, or by the provision of auxiliary aids or services as provided in § 84.75.

(2) With respect to employment as provided in § 84.12, the term as defined by the Equal Employment Opportunity Commission's regulation implementing title I of the Americans with Disabilities Act of 1990, at 29 CFR 1630.2(r).

Director means the Director of the Office for Civil Rights.

Disability means:

(1) Except as provided in paragraph (2) of this definition, the definition of *disability* found at § 84.4.

(2) With respect to employment, the definition of *disability* found at 29 CFR 1630.2.

Drug means a controlled substance, as defined in schedules I through V of section 202 of the Controlled Substances Act (21 U.S.C. 812).

Existing facility means a facility in existence on any given date, without regard to whether the facility may also be considered newly constructed or altered under this part.

Facility means all or any portion of buildings, structures, sites, complexes, equipment, rolling stock or other conveyances, roads, walks, passageways, parking lots, or other real or personal property, including the site where the building, property, structure, or equipment is located.

Federal financial assistance means any grant, cooperative agreement, loan, contract (other than a direct Federal procurement contract or a contract of insurance or guaranty), subgrant, contract under a grant or any other arrangement by which the Department provides or otherwise makes available assistance in the form of:

(1) Funds;

(2) Services of Federal personnel;

(3) Real and personal property or any interest in or use of such property, including:

(i) Transfers or leases of such property for less than fair market value or for reduced consideration; and

(ii) Proceeds from a subsequent transfer or lease of such property if the Federal share of its fair market value is not returned to the Federal Government; and

(4) Any other thing of value by way of grant, loan, contract, or cooperative agreement.

Foster care means 24-hour substitute care for children placed away from their parents or guardians and for whom the State agency has placement and care responsibility. This includes, but is not limited to, placements in foster family homes, foster homes of relatives, group homes, emergency shelters, residential facilities, childcare institutions, and pre-adoptive homes. A child is in foster care in accordance with this definition regardless of whether the foster care facility is licensed and payments are made by the State or local agency for the care of the child, whether adoption subsidy payments are being made prior to the finalization of an adoption, or whether there is Federal matching of any payments that are made.

Illegal use of drugs means the use of one or more drugs, the possession or distribution of which is unlawful under the Controlled Substances Act (21 U.S.C. 812). The term illegal use of drugs does not include the use of a drug taken under supervision by a licensed health care professional, or other uses authorized by the Controlled Substances Act or other provisions of Federal law.

Individual with a disability means a person who has a disability. The term *individual with a disability* does not include an individual who is currently engaging in illegal use of drugs when a recipient acts on the basis of such use.

Kiosks means self-service transaction machines made available by recipients at set physical locations for the independent use of patients or program participants in health and human service programs or activities. They often consist of a screen and an input device—either a keyboard, touch screen, or similar device—onto which the program participant independently types in or otherwise enters information. In health and human service programs, recipients often make kiosks available so that patients or program participants can check in, provide information for the receipt of services, procure services, have their vital signs taken, or perform other similar actions.

Medical diagnostic equipment (MDE) means equipment used in, or in conjunction with, medical settings by health care providers for diagnostic purposes. MDE includes, for example, examination tables, examination chairs (including chairs used for eye examinations or procedures, and dental examinations or procedures), weight scales, mammography equipment, x-ray machines, and other radiological equipment commonly used for diagnostic purposes by health professionals.

Mobile applications (apps) means software applications that are downloaded and designed to run on mobile devices, such as smartphones and tablets.

Most integrated setting means a setting that provides individuals with disabilities the opportunity to interact with nondisabled persons to the fullest extent possible. These settings provide opportunities to live, work, and receive services in the greater community, like individuals without disabilities; are located in mainstream society; offer access to community activities and opportunities at times, frequencies and with persons of an individual's choosing; and afford individuals choice in their daily life activities.

Other power-driven mobility device means any mobility device powered by batteries, fuel, or other engines—whether or not designed primarily for use by individuals with mobility disabilities—that is used by individuals with mobility disabilities for the purpose of locomotion, including golf cars, electronic personal assistance mobility devices (EPAMDs), such as the Segway® PT, or any mobility device designed to operate in areas without defined pedestrian routes, but that is not

a wheelchair within the meaning of this section. This definition does not apply to Federal wilderness areas; wheelchairs in such areas are defined in section 508(c)(2) of the ADA, 42 U.S.C. 12207(c)(2).

Parents means biological or adoptive parents or legal guardians, as determined by applicable State law.

Program or activity means all of the operations of any entity described in paragraphs (1) through (4) of this definition, any part of which is extended Federal financial assistance:

(1)(i) A department, agency, special purpose district, or other instrumentality of a State or of a local government; or

(ii) The entity of such State or local government that distributes such assistance and each such department or agency (and each other State or local government entity) to which the assistance is extended, in the case of assistance to a State or local government;

(2)(i) A college, university, or other postsecondary institution, a public system of higher education; or

(ii) A local educational agency (as defined in 20 U.S.C. 7801), system of career and technical education, or other school system;

(3)(i) An entire corporation, partnership, or other private organization, or an entire sole proprietorship—

(A) If assistance is extended to such corporation, partnership, private organization, or sole proprietorship as a whole; or

(B) Which is principally engaged in the business of providing education, health care, housing, social services, or parks and recreation; or

(ii) The entire plant or other comparable, geographically separate facility to which Federal financial assistance is extended, in the case of any other corporation, partnership, private organization, or sole proprietorship; or

(4) Any other entity which is established by two or more of the entities described in paragraph (1), (2), or (3) of this definition.

Prospective parents means individuals who are seeking to become foster or adoptive parents.

Qualified individual with a disability means:

(1) Except as provided in paragraphs (2) through (4) of this definition, an individual with a disability who, with or without reasonable modifications to rules, policies, or practices, the removal of architectural, communication, or transportation barriers, or the provision of auxiliary aids and services, meets the essential eligibility requirements for the receipt of services or the participation in programs or activities provided by a recipient; and

(2) With respect to employment, an individual with a disability who meets the definition of ''qualified'' in the Equal Employment Opportunity Commission's regulation implementing title I of the Americans with Disabilities Act of 1990, 29 CFR 1630.2(m).

(3) With respect to childcare, preschool, elementary, secondary, or adult educational services, a person with a disability—

(i) Of an age during which nondisabled persons are provided such services;

(ii) Of any age during which it is mandatory under State law to provide such services to persons with a disability; or

(iii) To whom a State is required to provide a free appropriate public education under the Individuals with Disabilities Education Act; and

(4) With respect to postsecondary and career and technical education services, an individual with a disability who, with or without reasonable modifications to rules, policies, or practices, the removal of architectural, communication, or transportation barriers, or the provision of auxiliary aids and services, meets the essential eligibility requirements for the receipt of services or the participation in the recipient's program or activity.

Qualified interpreter means an interpreter who, via an on-site appearance or through a video remote interpreting (VRI) service, is able to interpret effectively, accurately, and impartially, both receptively and expressively, using any necessary specialized vocabulary. Qualified interpreters include, for example, sign language interpreters, oral transliterators, and cued-language transliterators.

Qualified reader means a person who is able to read effectively, accurately, and impartially using any necessary specialized vocabulary.

Recipient means any State or its political subdivision, any instrumentality of a State or its political subdivision, any public or private agency, institution, organization, or other entity, or any person to which Federal financial assistance is extended directly or through another recipient, including any successor, assignee, or transferee of a recipient, but excluding the ultimate beneficiary of the assistance.

Section 504 means section 504 of the Rehabilitation Act of 1973 (Pub. L. 93–112, 87 Stat. 394 (29 U.S.C. 794)), as amended.

Section 508 Standards means the standards for Information and Communications Technologies (ICT) promulgated at 36 CFR part 1194 by the U.S. Access Board per section 508 of the Rehabilitation Act (29 U.S.C. 794d as amended).

Service animal means any dog that is individually trained to do work or perform tasks for the benefit of an individual with a disability, including a physical, sensory, psychiatric, intellectual, or other mental disability. Other species of animals, whether wild or domestic, trained or untrained, are not service animals for the purposes of this definition. The work or tasks performed by a service animal must be directly related to the individual's disability. Examples of work or tasks include, but are not limited to, assisting individuals who are blind or have low vision with navigation and other tasks, alerting individuals who are deaf or hard of hearing to the presence of people or sounds, providing non-violent protection or rescue work, pulling a wheelchair, assisting an individual during a seizure, alerting individuals to the presence of allergens, retrieving items such as medicine or the telephone, providing physical support and assistance with balance and stability to individuals with mobility disabilities, and helping persons with mental and neurological disabilities by preventing or interrupting impulsive or harmful behaviors. The crime deterrent effects of an animal's presence and the provision of emotional support, well-being, comfort, or companionship do not constitute work or tasks for the purposes of this definition.

Standards for Accessible Medical Diagnostic Equipment (''Standards for Accessible MDE'') means the standards promulgated by the Architectural and Transportation Barriers Compliance Board (Access Board) under section 510 of the Rehabilitation Act of 1973, as amended, found at 36 CFR part 1195 (as of Jan. 9, 2017), with the exception of M301.2.2 and M302.2.2.

State includes, in addition to each of the several States of the United States, the District of Columbia, the Commonwealth of Puerto Rico, the United States Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.

Ultimate beneficiary means one among a class of persons who are entitled to benefit from, or otherwise participate in, a program or activity receiving Federal financial assistance and to whom the protections of this part

extend. The ultimate beneficiary class may be the general public or some narrower group of persons.

User agent means any software that retrieves and presents web content for users.

Video remote interpreting (VRI) service means an interpreting service that uses video conference technology over dedicated lines or wireless technology offering high-speed, wide-bandwidth video connection that delivers high-quality video images as provided in § 84.77(d).

WCAG 2.1 means the Web Content Accessibility Guidelines (WCAG) 2.1, W3C Recommendation 05 June 2018, *https://www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F.* WCAG 2.1 is incorporated by reference elsewhere in this part (see §§ 84.84 and 84.86).

Web content means the information and sensory experience to be communicated to the user by means of a user agent, including code or markup that defines the content's structure, presentation, and interactions. Examples of web content include text, images, sounds, videos, controls, animations, and conventional electronic documents.

Wheelchair means a manually-operated or power-driven device designed primarily for use by an individual with a mobility disability for the main purpose of indoor, or of both indoor and outdoor locomotion. This definition does not apply to Federal wilderness areas; wheelchairs in such areas are defined in section 508(c)(2) of the ADA, 42 U.S.C. 12207(c)(2).

■ 12. Revise subpart B to read as follows:

Subpart B—Employment Practices

Sec.
84.16 Discrimination prohibited.
84.17–84.20 [Reserved]

Subpart B—Employment Practices

§ 84.16 Discrimination prohibited.

(a) No qualified individual with a disability shall, on the basis of disability, be subjected to discrimination in employment under any program or activity receiving Federal financial assistance from the Department.

(b) The standards used to determine whether paragraph (a) of this section has been violated shall be the standards applied under title I of the Americans with Disabilities Act of 1990 (ADA), 42 U.S.C. 12111 *et seq.,* and, as such sections relate to employment, the provisions of sections 501 through 504 and 511 of the ADA of 1990, as amended (codified at 42 U.S.C. 12201–12204, 12210), as implemented in the Equal Employment Opportunity Commission's regulation at 29 CFR part 1630.

§§ 84.17–84.20 [Reserved]

Subpart C—Program Accessibility

■ 13. Revise § 84.21 to read as follows:

§ 84.21 Discrimination prohibited.

Except as otherwise provided in § 84.22, no qualified individual with a disability shall, because a recipient's facilities are inaccessible to or unusable by individuals with disabilities, be excluded from participation in, or be denied the benefits of the programs or activities of a recipient, or be subjected to discrimination by any recipient.

■ 14. Amend § 84.22 by:
■ a. Revising paragraphs (a) and (b);
■ b. Removing the words ''handicapped person'' and adding in their place the words ''person with a disability'' wherever they occur in paragraph (c);
■ c. Removing the words ''handicapped persons'' and adding in their place the words ''persons with disabilities'' wherever they occur in paragraphs (e) introductory text, (e)(1), and (f); and
■ d. Adding paragraph (g).

The revisions and addition read as follows:

§ 84.22 Existing facilities.

(a) *General.* A recipient shall operate each program or activity so that the program or activity, when viewed in its entirety, is readily accessible to and usable by individuals with disabilities. This paragraph (a) does not—

(1) Necessarily require a recipient to make each of its existing facilities accessible to and usable by individuals with disabilities; or

(2) Require a recipient to take any action that it can demonstrate would result in a fundamental alteration in the nature of a program or activity or in undue financial and administrative burdens. In those circumstances where a recipient's personnel believe that the proposed action would fundamentally alter the program or activity or would result in undue financial and administrative burdens, the recipient has the burden of proving that compliance with this paragraph (a) would result in such an alteration or burdens. The decision that compliance would result in such alteration or burdens must be made by the head of the recipient or their designee after considering all the recipient's resources available for use in the funding and operation of the program or activity, and must be accompanied by a written statement of the reasons for reaching that conclusion. If an action would result in such an alteration or such burdens, the recipient shall take any other action that would not result in such an alteration or such burdens but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient.

(b) *Methods.* A recipient may comply with the requirements of this section through such means as redesign or acquisition of equipment, reassignment of services to accessible buildings, assignment of aides to beneficiaries, home visits, delivery of services at alternate accessible sites, alteration of existing facilities and construction of new facilities, use of accessible rolling stock or other conveyances, or any other methods that result in making its programs or activities readily accessible to and usable by individuals with disabilities. A recipient is not required to make structural changes in existing facilities where other methods are effective in achieving compliance with this section. A recipient, in making alterations to existing buildings, shall meet the accessibility requirements of § 84.23. In choosing among available methods for meeting the requirements of this section, a recipient shall give priority to those methods that offer programs and activities to qualified individuals with disabilities in the most integrated setting appropriate.

* * * * *

(g) *Safe harbor.* Elements that have not been altered in existing facilities on or after July 8, 2024, and that comply with the corresponding technical and scoping specifications for those elements in the American National Standard Specification (ANSI) (ANSI A117.1–1961(R1971)) for facilities constructed between June 3, 1977, and January 18, 1991) or for those elements in the Uniform Federal Accessibility Standards (UFAS), appendix A to 41 CFR part 101–19, subpart 101–19.6 (revised as of July 1, 2002), for those facilities constructed between January 18, 1991, and July 8, 2024, are not required to be modified to comply with the requirements set forth in the 2010 Standards.

■ 15. Revise § 84.23 to read as follows:

§ 84.23 New construction and alterations.

(a) *Design and construction.* Each facility or part of a facility constructed by, on behalf of, or for the use of a recipient shall be designed and constructed in such manner that the facility or part of the facility is readily accessible to and usable by individuals

with disabilities, if the construction was commenced after June 3, 1977.

(b) *Alterations.* Each facility or part of a facility altered by, on behalf of, or for the use of a recipient in a manner that affects or could affect the usability of the facility or part of the facility shall, to the maximum extent feasible, be altered in such manner that the altered portion of the facility is readily accessible to and usable by individuals with disabilities, if the alteration was commenced after June 3, 1977.

(c) *Accessibility standards and compliance dates for recipients that are public entities.* (1) The accessibility standards and compliance dates in this paragraph (c) apply to recipients that are public entities. Public entities are any State or local government; any department, agency, special purpose district, or other instrumentality of a State or States or local government; and the National Railroad Passenger Corporation, and any commuter authority (as defined in section 103(8) of the Rail Passenger Service Act). (45 U.S.C. 541)

(2) If physical construction or alterations commenced after June 3, 1977, but before January 18, 1991, then construction and alterations subject to this section shall be deemed in compliance with this section if they meet the requirements of the ANSI Standards (ANSI A117.1–1961(R1971)) (ANSI). Departures from particular requirements of ANSI by the use of other methods are permitted when it is clearly evident that equivalent access to the facility or part of the facility is provided.

(3) If physical construction or alterations commence on or after January 18, 1991, but before July 8, 2024, then new construction and alterations subject to this section shall be deemed in compliance with this section if they meet the requirements of the Uniform Federal Accessibility Standards (UFAS), appendix A to 41 CFR part 101–19, subpart 101–19.6 (revised as of July 1, 2002). Departures from particular requirements of UFAS by the use of other methods shall be permitted when it is clearly evident that equivalent access to the facility or part of the facility is thereby provided.

(4) For physical construction or alterations that commence on or after July 8, 2024, but before May 9, 2025, then new construction and alterations subject to this section may comply with either UFAS or the 2010 Standards. Departures from particular requirements of either standard by the use of other methods shall be permitted when it is clearly evident that equivalent access to the facility or part of the facility is thereby provided.

(5) If physical construction or alterations commence on or after May 9, 2025, then new construction and alterations subject to this section shall comply with the 2010 Standards.

(6) For the purposes of this section, ceremonial groundbreaking or razing of structures prior to site preparation do not commence physical construction or alterations.

(d) *Accessibility standards and compliance dates for recipients that are private entities.* (1) The accessibility standards and compliance dates in this paragraph (d) apply to recipients that are private entities. Private entities are any person or entity other than a public entity.

(2) New construction and alterations subject to this section where the date when the last application for a building permit or permit extension is certified to be complete by a State, county, or local government or, in those jurisdictions where the government does not certify completion of applications, if the date when the last application for a building permit or permit extension is received by the State, county, or local government between June 3, 1977, and January 18, 1991, or if no permit is required, if the start of physical construction or alterations occurs between June 3, 1977, and January 18, 1991, shall be deemed in compliance with this section if they meet the requirements of ANSI. Departures from particular requirements of ANSI by the use of other methods are permitted when it is clearly evident that equivalent access to the facility or part of the facility is provided.

(3) New construction and alterations subject to this section shall comply with UFAS if the date when the last application for a building permit or permit extension is certified to be complete by a State, county, or local government (or, in those jurisdictions where the government does not certify completion of applications, if the date when the last application for a building permit or permit extension is received by the State, county, or local government) is on or after January 18, 1991, and before July 8, 2024, or if no permit is required, if the start of physical construction or alterations occurs on or after January 18, 1991, and before July 8, 2024. Departures from particular requirements of UFAS by the use of other methods are permitted when it is clearly evident that equivalent access to the facility or part of the facility is provided.

(4) New construction and alterations subject to this section shall comply either with UFAS or the 2010 Standards if the date when the last application for a building permit or permit extension is certified to be complete by a State, county, or local government (or, in those jurisdictions where the government does not certify completion of applications, if the date when the last application for a building permit or permit extension is received by the State, county, or local government) is on or after July 8, 2024, and before May 9, 2025, or if no permit is required, if the start of physical construction or alterations occurs on or after July 8, 2024, and before May 9, 2025. Departures from particular requirements of either standard by the use of other methods shall be permitted when it is clearly evident that equivalent access to the facility or part of the facility is thereby provided.

(5) New construction and alterations subject to this section shall comply with the 2010 Standards if the date when the last application for a building permit or permit extension is certified to be complete by a State, county, or local government (or, in those jurisdictions where the government does not certify completion of applications, if the date when the last application for a building permit or permit extension is received by the State, county, or local government) is on or after May 9, 2025, or if no permit is required, if the start of physical construction or alterations occurs on or after May 9, 2025.

(6) For the purposes of this section, ceremonial groundbreaking or razing of structures prior to site preparation do not commence physical construction or alterations.

(e) *Noncomplying new construction and alterations.* (1) Newly constructed or altered facilities or elements covered by paragraph (a) or (b) of this section that were constructed or altered between June 3, 1977, and January 18, 1991, and that do not comply with ANSI shall be made accessible in accordance with the 2010 Standards.

(2) Newly constructed or altered facilities or elements covered by paragraph (a) or (b) of this section that were constructed or altered on or after January 18, 1991, and before May 9, 2025, and that do not comply with UFAS shall before May 9, 2025, be made accessible in accordance with either UFAS or the 2010 Standards.

(3) Newly constructed or altered facilities or elements covered by paragraph (a) or (b) of this section that were constructed or altered before May 9, 2025, and that do not comply with ANSI (for facilities constructed or altered between June 3, 1977, and January 18, 1991) or UFAS (for facilities

constructed or altered on or after January 18, 1991) shall, on or after May 9, 2025, be made accessible in accordance with the 2010 Standards.

(f) *Public buildings or facilities requirements.* New construction and alterations of buildings or facilities undertaken in compliance with the 2010 Standards will comply with the scoping and technical requirements for a ''public building or facility'' regardless of whether the recipient is a public entity as defined in 28 CFR 35.104 or a private entity.

(g) *Compliance with the Architectural Barriers Act of 1968.* Nothing in this section relieves recipients whose facilities are covered by the Architectural Barriers Act, from their responsibility of complying with the requirements of the Architectural Barriers Act and its implementing regulations, 41 CFR 102–76.60 through 102–76.95 (General Services Administration); 39 CFR part 255 (U.S. Postal Service); 24 CFR part 40 (U.S. Department of Housing and Urban Development); and the U.S. Department of Defense ''Policy Memorandum for Secretaries of the Military Departments: Access for People with Disabilities'' (October 31, 2008).

(h) *Mechanical rooms.* For purposes of this section, section 4.1.6(1)(g) of UFAS will be interpreted to exempt from the requirements of UFAS only mechanical rooms and other spaces that, because of their intended use, will not require accessibility to the public or beneficiaries or result in the employment or residence therein of individuals with physical disabilities.

■ 16. Revise the heading of subpart D to read as follows:

Subpart D—Childcare, Preschool, Elementary and Secondary, and Adult Education

■ 17. Revise § 84.31 to read as follows:

§ 84.31 Application of this subpart.

This subpart applies to childcare, preschool, elementary and secondary, and adult education programs or activities that receive Federal financial assistance and to recipients that operate, or that receive Federal financial assistance for the operation of, such programs or activities.

§§ 84.32 through 84.37 [Removed and Reserved]

■ 18. Remove and reserve §§ 84.32 through 84.37.

■ 19. Revise § 84.38 to read as follows:

§ 84.38 Childcare, preschool, elementary and secondary, and adult education.

A recipient to which this subpart applies that provides childcare, preschool, elementary and secondary, or adult education may not, on the basis of disability, exclude qualified individuals with disabilities and shall take into account the needs of such persons in determining the aids, benefits, or services to be provided.

§ 84.39 [Removed and Reserved]

■ 20. Remove and reserve § 84.39.

Subpart E—Postsecondary Education

§ 84.42 [Amended]

■ 21. Amend § 84.42 by:
■ a. Removing the word ''handicap'' and adding in its place the word ''disability'' in paragraphs (a) and (b)(3)(i);
■ b. Removing the words ''handicapped persons'' and adding in their place the words ''persons with disabilities'' wherever they occur in paragraphs (a), (b)(1), (b)(2) introductory text, and (b)(3)(iii);
■ c. Removing the words ''handicapped person'' and ''handicaps'' and adding in their places the words ''person with a disability'' and ''disabilities'', respectively, in paragraph (b)(4); and
■ d. Removing the word ''handicapped'' and adding in its place the word ''disabled'' in paragraph (c) introductory text.

§ 84.43 [Amended]

■ 22. Amend § 84.43 by:
■ a. Removing the words ''handicapped student'' and ''handicap'' and adding in their places the words ''student with a disability'' and ''disability'', respectively, in paragraphs (a) and (c); and
■ b. Removing the words ''handicapped persons'' and adding in their place the words ''persons with disabilities'' in paragraph (b).

§ 84.44 [Amended]

■ 23. Amend § 84.44 by:
■ a. Removing the word ''handicap'' and adding in its place the word ''disability'' in paragraphs (a) and (c);
■ b. Removing the words ''handicapped applicant or student'' and adding in their place the words ''applicant or student with a disability'' in paragraph (a);
■ c. Removing the words ''handicapped students'' and adding in their place the words ''students with disabilities'' wherever they occur in paragraph (b); and
■ d. Removing the words ''handicapped student'' and adding in their place the words ''student with a disability'' in paragraph (d)(1).

§ 84.45 [Amended]

■ 24. Amend § 84.45 by:
■ a. Revising paragraph (a); and
■ b. Removing the word ''handicap'' and adding in its place the word ''disability'' in paragraph (b).

The revision reads as follows:

§ 84.45 Housing.

(a) *Housing provided by the recipient.* A recipient that provides housing to its students without disabilities shall provide comparable, convenient, and accessible housing to students with disabilities at the same cost as to others. At the end of the transition period provided for in subpart C of this part, such housing shall be available in sufficient quantity and variety so that the scope of students with disabilities' choice of living accommodations is, as a whole, comparable to that of students without disabilities.

* * * * *

§ 84.46 [Amended]

■ 25. Amend § 84.46 by:
■ a. Removing the word ''handicap'' and adding in its place the word ''disability'' wherever it occurs in paragraph (a);
■ b. Removing the words ''handicapped persons'' and adding in their place the words ''persons with disabilities'' wherever they occur in paragraph (a)(1); and
■ c. Removing the words ''nonhandicapped persons'' and adding in their place the words ''persons without disabilities'' in paragraph (a)(1).

§ 84.47 [Amended]

■ 26. Amend § 84.47 by:
■ a. Removing the word ''handicap'' and adding in its place the word ''disability'' in paragraphs (a)(1) and (b);
■ b. Removing the words ''handicapped students'' and adding in their place the words ''students with disabilities'' in paragraphs (a)(1) and (2) and (b);
■ c. Removing the words ''handicapped student'' and adding in their place the words ''student with a disability'' in paragraph (a)(2); and
■ d. Removing the words ''nonhandicapped students'' and ''handicapped persons'' and adding in their places the words ''students without disabilities'' and ''persons with disabilities'', respectively, in paragraph (b).

Subpart F—Health, Welfare, and Social Services

§ 84.52 [Amended]

■ 27. Amend § 84.52 by:
■ a. Removing the words ''handicapped person'' and adding in its place the

words ''person with a disability'' in paragraphs (a)(1) through (3);
■ b. Removing the words ''nonhandicapped persons'' and adding in their place the words ''persons without disabilities'' in paragraph (a)(2);
■ c. Removing the words ''handicapped persons'' and adding in their place the words ''persons with disabilities'' wherever they occur in paragraphs (a)(4) and (5) and (b);
■ d. Removing the word ''handicap'' and adding in its place the word ''disability'' in paragraph (b); and
■ e. Removing paragraphs (c) and (d).

■ 28. Revise § 84.53 to read as follows:

§ 84.53 Individuals with substance and alcohol use disorders.

A recipient to which this subpart applies that operates a health care facility may not discriminate in admission or treatment against an individual with a substance or alcohol use disorder who has a medical condition, because of the person's substance or alcohol use disorder.

■ 29. Revise § 84.54 to read as follows:

§ 84.54 Education of institutionalized persons.

A recipient to which this subpart applies and that provides aids, benefits, or services to persons who are institutionalized because of disability shall ensure that each qualified individual with disabilities, as defined in § 84.10, in its program or activity is provided an appropriate education, consistent with the Department of Education section 504 regulations at 34 CFR 104.33(b). Nothing in this section shall be interpreted as altering in any way the obligations of recipients under subpart D of this part.

§ 84.55 [Amended]

■ 30. Amend § 84.55 by:
■ a. Removing the words ''handicapped infants'' and adding in their place the words ''infants with disabilities'' in the section heading, paragraph (a), and paragraph (f) introductory text;
■ b. Removing the words ''handicapped infants'' and adding in their place the words ''infants with disabilities'' in paragraphs (f)(1)(i), (f)(1)(ii)(A), and (f)(1)(ii)(C);
■ c. Removing the word ''handicaps'' and adding in its place the word ''disabilities'' in paragraph (f)(1)(ii)(C); and
■ d. Removing and reserving paragraphs (b) through (e).

■ 31. Add §§ 84.56 and 84.57 to read as follows:

§ 84.56 Medical treatment.

(a) *Discrimination prohibited.* No qualified individual with a disability shall, on the basis of disability, be subjected to discrimination in medical treatment under any program or activity that receives Federal financial assistance, including in the allocation or withdrawal of any good, benefit, or service.

(b) *Specific prohibitions.* The general prohibition in paragraph (a) of this section includes the following specific prohibitions:

(1) *Denial of medical treatment.* A recipient may not deny or limit medical treatment to a qualified individual with a disability when the denial is based on:

(i) Bias or stereotypes about a patient's disability;

(ii) Judgments that the individual will be a burden on others due to their disability, including, but not limited to caregivers, family, or society; or

(iii) A belief that the life of a person with a disability has lesser value than the life of a person without a disability, or that life with a disability is not worth living.

(2) *Denial of treatment for a separate symptom or condition.* Where a qualified individual with a disability or their authorized representative seeks or consents to treatment for a separately diagnosable symptom or medical condition (whether or not that symptom or condition is a disability under this part or is causally connected to the individual's underlying disability), a recipient may not deny or limit clinically appropriate treatment if it would be offered to a similarly situated individual without an underlying disability.

(3) *Provision of medical treatment.* A recipient may not, on the basis of disability, provide a medical treatment to an individual with a disability where it would not provide the same treatment to an individual without a disability, unless the disability impacts the effectiveness, or ease of administration of the treatment itself, or has a medical effect on the condition to which the treatment is directed.

(c) *Construction*—(1) *Professional judgment in treatment.* (i) Nothing in this section requires the provision of medical treatment where the recipient has a legitimate, nondiscriminatory reason for denying or limiting that service or where the disability renders the individual not qualified for the treatment.

(ii) Circumstances in which the recipient has a legitimate, nondiscriminatory reason for denying or limiting a service or where the disability renders the individual not qualified for the treatment may include circumstances in which the recipient typically declines to provide the treatment to any individual, or reasonably determines based on current medical knowledge or the best available objective evidence that such medical treatment is not clinically appropriate for a particular individual. The criteria in paragraphs (b)(1)(i) through (iii) of this section are not a legitimate nondiscriminatory reason for denying or limiting medical treatment and may not be a basis for a determination that an individual is not qualified for the treatment, or that a treatment is not clinically appropriate for a particular individual.

(2) *Consent.* (i) Nothing in this section requires a recipient to provide medical treatment to an individual where the individual, or their authorized representative, does not consent to that treatment.

(ii) Nothing in this section allows a recipient to discriminate against a qualified individual with a disability on the basis of disability in seeking to obtain consent from an individual or their authorized representative for the recipient to provide, withhold, or withdraw treatment.

(3) *Providing information.* Nothing in this section precludes a provider from providing an individual with a disability or their authorized representative with information regarding the implications of different courses of treatment based on current medical knowledge or the best available objective evidence.

§ 84.57 Value assessment methods.

A recipient shall not, directly or through contractual, licensing, or other arrangements, use any measure, assessment, or tool that discounts the value of life extension on the basis of disability to deny or afford an unequal opportunity to qualified individuals with disabilities with respect to the eligibility or referral for, or provision or withdrawal of any aid, benefit, or service, including the terms or conditions under which they are made available.

■ 32. Add § 84.60 to read as follows:

§ 84.60 Children, parents, caregivers, foster parents, and prospective parents in the child welfare system.

(a) *Discriminatory actions prohibited.* (1) No qualified individual with a disability shall, on the basis of disability, be excluded from participation in, be denied the benefits of, or otherwise be subjected to discrimination under any child welfare program or activity that receives Federal financial assistance.

(2) Under the prohibition set forth in paragraph (a)(1) of this section, discrimination includes:

(i) Decisions based on speculation, stereotypes, or generalizations that a parent, caregiver, foster parent, or prospective parent, because of a disability, cannot safely care for a child; and

(ii) Decisions based on speculation, stereotypes, or generalizations about a child with a disability.

(b) *Additional prohibitions.* The prohibitions in paragraph (a) of this section apply to actions by a recipient of Federal financial assistance made directly or through contracts, agreements, or other arrangements, including any action to:

(1) Deny a qualified parent with a disability custody or control of, or visitation to, a child;

(2) Deny a qualified parent with a disability an opportunity to participate in or benefit from any and all services provided by a child welfare agency, including but not limited to, family preservation and reunification services equal to that afforded to persons without disabilities;

(3) Terminate the parental rights or legal guardianship of a qualified individual with a disability;

(4) Deny a qualified caregiver, foster parent, companion, or prospective parent with a disability the opportunity to participate in or benefit from child welfare programs and activities; or

(5) Require children, on the basis on the disability, to be placed outside the family home through custody relinquishment, voluntary placement, or other forfeiture of parental rights in order to receive necessary services.

(c) *Parenting evaluation procedures.* A recipient to which this subpart applies shall establish procedures for referring to qualified professionals for evaluation those individuals, who, because of disability, need or are believed to need adapted services or reasonable modifications. A recipient shall also ensure that tests, assessments, and other evaluation tools and materials used for the purpose of assessing or evaluating parenting ability are based in evidence or research, are conducted by a qualified professional and are tailored to assess actual parenting ability and specific areas of disability-related needs. Parenting evaluations must be fully accessible to people with disabilities and shall not be based on a single general intelligence quotient or measure of the person's disability, rather than their parenting ability. Assessments of parents or children must be individualized and based on the best available objective evidence.

■ 33. Revise subpart G to read as follows:

Subpart G—General Requirements

Sec.
84.68 General prohibitions against discrimination.
84.69 Illegal use of drugs.
84.70 Maintenance of accessible features.
84.71 Retaliation or coercion.
84.72 Personal devices and services.
84.73 Service animals.
84.74 Mobility devices.
84.75 Direct threat.
84.76 Integration.

Subpart G—General Requirements

§ 84.68 General prohibitions against discrimination.

(a) No qualified individual with a disability shall, solely on the basis of disability, be excluded from participation in or be denied the benefits of the programs or activities of a recipient, or be subjected to discrimination by any recipient.

(b)(1) A recipient, in providing any aid, benefit, or service, may not, directly or through contractual, licensing, or other arrangements, on the basis of disability—

(i) Deny a qualified individual with a disability the opportunity to participate in or benefit from the aid, benefit, or service.

(ii) Afford a qualified individual with a disability an opportunity to participate in or benefit from the aid, benefit, or service that is not equal to that afforded others.

(iii) Provide a qualified individual with a disability an aid, benefit, or service that is not as effective in affording equal opportunity to obtain the same result, to gain the benefit or to reach the same level of achievement as that provided to others.

(iv) Provide different or separate aids, benefits, or services to individuals with disabilities or to any class of individuals with disabilities than is provided to others unless such action is necessary to provide qualified individuals with disabilities with aids, benefits, or services that are as effective as those provided to others.

(v) Aid or perpetuate discrimination against a qualified individual with a disability by providing significant assistance to an agency, organization, or person that discriminates on the basis of disability in providing any aid, benefit, or service to beneficiaries of the recipient's program.

(vi) Deny a qualified individual with a disability the opportunity to participate as a member of planning or advisory boards.

(vii) Otherwise limit a qualified individual with a disability in the enjoyment of any right, privilege, advantage, or opportunity enjoyed by others receiving the aid, benefit, or service.

(2) A recipient may not deny a qualified individual with a disability the opportunity to participate in programs or activities that are not separate or different, despite the existence of permissibly separate or different programs or activities.

(3) A recipient may not, directly or through contractual or other arrangements, utilize criteria or methods of administration—

(i) That have the effect of subjecting qualified individuals with disabilities to discrimination on the basis of disability;

(ii) That have the purpose or effect of defeating or substantially impairing accomplishment of the objectives of the recipient's program with respect to individuals with disabilities; or

(iii) That perpetuate the discrimination of another recipient if both recipients are subject to common administrative control or are agencies of the same state.

(4) A recipient may not, in determining the site or location of a facility, make selections—

(i) That have the effect of excluding individuals with disabilities from, denying them the benefits of, or otherwise subjecting them to discrimination; or

(ii) That have the purpose or effect of defeating or substantially impairing the accomplishment of the objectives of the program or activity with respect to individuals with disabilities.

(5) A recipient, in the selection of procurement contractors, may not use criteria that subject qualified individuals with disabilities to discrimination on the basis of disability.

(6) A recipient may not administer a licensing or certification program in a manner that subjects qualified individuals with disabilities to discrimination on the basis of disability, nor may a recipient establish requirements for the programs or activities of licensees or certified entities that subject qualified individuals with disabilities to discrimination on the basis of disability. The programs or activities of entities that are licensed or certified by the recipient are not, themselves, covered by this part.

(7)(i) A recipient shall make reasonable modifications in policies, practices, or procedures when such modifications are necessary to avoid discrimination on the basis of disability, unless the recipient can demonstrate that making the modifications would

fundamentally alter the nature of the program or activity.

(ii) A recipient is not required to provide a reasonable modification to an individual who meets the definition of ''disability'' solely under the ''regarded as'' prong of the definition of disability in § 84.4(a)(1)(iii).

(8) A recipient shall not impose or apply eligibility criteria that screen out or tend to screen out an individual with a disability or any class of individuals with disabilities from fully and equally enjoying any program or activity, unless such criteria can be shown to be necessary for the provision of the program or activity being offered.

(c) Nothing in this part prohibits a recipient from providing benefits, services, or advantages to individuals with disabilities, or to a particular class of individuals with disabilities beyond those required by this part.

(d) A recipient shall administer programs and activities in the most integrated setting appropriate to the needs of qualified individuals with disabilities.

(e)(1) Nothing in this part shall be construed to require an individual with a disability to accept a modification, aid, service, opportunity, or benefit provided under section 504 or this part which such individual chooses not to accept.

(2) Nothing in section 504 or this part authorizes the representative or guardian of an individual with a disability to decline food, water, medical treatment, or medical services for that individual.

(f) A recipient may not place a surcharge on a particular individual with a disability or any group of individuals with disabilities to cover the costs of measures, such as the provision of auxiliary aids or program accessibility, that are required to provide that individual or group with the nondiscriminatory treatment required by section 504 or this part.

(g) A recipient shall not exclude or otherwise deny equal programs or activities to an individual or entity because of the known disability of an individual with whom the individual or entity is known to have a relationship or association.

(h) A recipient may impose legitimate safety requirements necessary for the safe operation of its programs or activities. However, the recipient must ensure that its safety requirements are based on actual risks, not on mere speculation, stereotypes, or generalizations about individuals with disabilities.

(i) Nothing in this part shall provide the basis for a claim that an individual without a disability was subject to discrimination because of a lack of disability, including a claim that an individual with a disability was granted a reasonable modification that was denied to an individual without a disability.

§ 84.69 Illegal use of drugs.

(a) *General.* (1) Except as provided in paragraph (b) of this section, this part does not prohibit discrimination against an individual based on that individual's current illegal use of drugs.

(2) A recipient shall not discriminate on the basis of illegal use of drugs against an individual who is not engaging in current illegal use of drugs and who—

(i) Has successfully completed a supervised drug rehabilitation program or has otherwise been rehabilitated successfully;

(ii) Is participating in a supervised rehabilitation program; or

(iii) Is erroneously regarded as engaging in such use.

(b) *Services provided under the Rehabilitation Act.* (1) A recipient shall not exclude an individual on the basis of that individual's current illegal use of drugs from the benefits of programs and activities providing health services and services provided under subchapters I, II, and III of the Rehabilitation Act, if the individual is otherwise entitled to such services.

(2) A drug rehabilitation or treatment program may deny participation to individuals who engage in illegal use of drugs while they are in the program.

(c) *Drug testing.* (1) This part does not prohibit the recipient from adopting or administering reasonable policies or procedures, including but not limited to drug testing, designed to ensure that an individual who formerly engaged in the illegal use of drugs is not now engaging in current illegal use of drugs.

(2) Nothing in this paragraph (c) shall be construed to encourage, prohibit, restrict, or authorize the conduct of testing for the illegal use of drugs.

§ 84.70 Maintenance of accessible features.

(a) A recipient shall maintain in operable working condition those features of facilities and equipment that are required to be readily accessible to and usable by persons with disabilities by section 504 or this part.

(b) This section does not prohibit isolated or temporary interruptions in service or access due to maintenance or repairs.

(c) For a recipient, if the 2010 Standards reduce the technical requirements or the number of required accessible elements below the number required by UFAS, the technical requirements or the number of accessible elements in a facility subject to this part may be reduced in accordance with the requirements of the 2010 Standards.

§ 84.71 Retaliation or coercion.

(a) A recipient shall not discriminate against any individual because that individual has opposed any act or practice made unlawful by this part, or because that individual made a charge, testified, assisted, or participated in any manner in an investigation, proceeding, or hearing under section 504 or this part.

(b) A recipient shall not coerce, intimidate, threaten, or interfere with any individual in the exercise or enjoyment of, or on account of their having exercised or enjoyed, or on account of their having aided or encouraged any other individual in the exercise or enjoyment of any right granted or protected by section 504 or this part.

§ 84.72 Personal devices and services.

This part does not require a recipient to provide to individuals with disabilities personal devices, such as wheelchairs; individually prescribed devices, such as prescription eyeglasses or hearing aids; readers for personal use or study; or services of a personal nature including assistance in eating, toileting, or dressing.

§ 84.73 Service animals.

(a) *General.* Generally, a recipient shall modify its policies, practices, or procedures to permit the use of a service animal by an individual with a disability.

(b) *Exceptions.* A recipient may ask an individual with a disability to remove a service animal from the premises if—

(1) The animal is out of control and the animal's handler does not take effective action to control it; or

(2) The animal is not housebroken.

(c) *If an animal is properly excluded.* If a recipient properly excludes a service animal under paragraph (b) of this section, it shall give the individual with a disability the opportunity to participate in the program or activity without having the service animal on the premises.

(d) *Animal under handler's control.* A service animal shall be under the control of its handler. A service animal shall have a harness, leash, or other tether, unless either the handler is unable because of a disability to use a harness, leash, or other tether, or the use of a harness, leash, or other tether

would interfere with the service animal's safe, effective performance of work or tasks, in which case the service animal must be otherwise under the handler's control (*e.g.,* voice control, signals, or other effective means).

(e) *Care or supervision.* A recipient is not responsible for the care or supervision of a service animal.

(f) *Inquiries.* A recipient shall not ask about the nature or extent of a person's disability but may make two inquiries to determine whether an animal qualifies as a service animal. A recipient may ask if the animal is required because of a disability and what work or task the animal has been trained to perform. A recipient shall not require documentation, such as proof that the animal has been certified, trained, or licensed as a service animal. Generally, a recipient may not make these inquiries about a service animal when it is readily apparent that an animal is trained to do work or perform tasks for an individual with a disability (*e.g.,* the dog is observed guiding an individual who is blind or has low vision, pulling a person's wheelchair, or providing assistance with stability or balance to an individual with an observable mobility disability).

(g) *Access to areas of the recipient.* Individuals with disabilities shall be permitted to be accompanied by their service animals in all areas of the recipient's facilities where members of the public, participants in programs or activities, or invitees, as relevant, are allowed to go.

(h) *Surcharges.* A recipient shall not ask or require an individual with a disability to pay a surcharge, even if people accompanied by pets are required to pay fees, or to comply with other requirements generally not applicable to people without pets. If a recipient normally charges individuals for the damage they cause, an individual with a disability may be charged for damage caused by their service animal.

(i) *Miniature horses*—(1) *Reasonable modifications.* A recipient shall make reasonable modifications in policies, practices, or procedures to permit the use of a miniature horse by an individual with a disability if the miniature horse has been individually trained to do work or perform tasks for the benefit of the individual with a disability.

(2) *Assessment factors.* In determining whether reasonable modifications in policies, practices, or procedures can be made to allow a miniature horse into a specific facility, a recipient shall consider—

(i) The type, size, and weight of the miniature horse and whether the facility can accommodate these features;

(ii) Whether the handler has sufficient control of the miniature horse;

(iii) Whether the miniature horse is housebroken; and

(iv) Whether the miniature horse's presence in a specific facility compromises legitimate safety requirements that are necessary for safe operation.

(3) *Other requirements.* Paragraphs (c) through (h) of this section, which apply to service animals, shall also apply to miniature horses.

§ 84.74 Mobility devices.

(a) *Use of wheelchairs and manually-powered mobility aids.* A recipient shall permit individuals with mobility disabilities to use wheelchairs and manually-powered mobility aids, such as walkers, crutches, canes, braces, or other similar devices designed for use by individuals with mobility disabilities in any areas open to pedestrian use.

(b) *Use of other power-driven mobility devices*—(1) *Requirement.* A recipient shall make reasonable modifications in its policies, practices, or procedures to permit the use of other power-driven mobility devices by individuals with mobility disabilities, unless a recipient can demonstrate that the class of other power-driven mobility devices cannot be operated in accordance with legitimate safety requirements that a recipient has adopted pursuant to § 84.68(h).

(2) *Assessment factors.* In determining whether a particular other power-driven mobility device can be allowed in a specific facility as a reasonable modification under paragraph (b)(1) of this section, a recipient shall consider—

(i) The type, size, weight, dimensions, and speed of the device;

(ii) The facility's volume of pedestrian traffic (which may vary at different times of the day, week, month, or year);

(iii) The facility's design and operational characteristics (*e.g.,* whether its program or activity is conducted indoors, its square footage, the density and placement of stationary devices, and the availability of storage for the device, if requested by the user);

(iv) Whether legitimate safety requirements can be established to permit the safe operation of the other power-driven mobility device in the specific facility; and

(v) Whether the use of the other power-driven mobility device creates a substantial risk of serious harm to the immediate environment or natural or cultural resources, or poses a conflict with Federal land management laws and regulations.

(c) *Inquiry about disability*—(1) *Requirement.* A recipient shall not ask an individual using a wheelchair or other power-driven mobility device questions about the nature and extent of the individual's disability.

(2) *Inquiry into use of other power-driven mobility device.* A recipient may ask a person using an other power-driven mobility device to provide a credible assurance that the mobility device is required because of the person's disability. A recipient in permitting the use of an other power-driven mobility device by an individual with a mobility disability shall accept the presentation of a valid, State-issued, disability parking placard or card, or other State-issued proof of disability as a credible assurance that the use of the other power-driven mobility device is for the individual's mobility disability. In lieu of a valid, State-issued disability parking placard or card, or State-issued proof of disability, a recipient shall accept as a credible assurance a verbal representation, not contradicted by observable fact, that the other power-driven mobility device is being used for a mobility disability. A ''valid'' disability placard or card is one that is presented by the individual to whom it was issued and is otherwise in compliance with the State of issuance's requirements for disability placards or cards.

§ 84.75 Direct threat.

(a) This part does not require a recipient to permit an individual to participate in or benefit from the programs or activities of that recipient when that individual poses a direct threat.

(b) Except as provided in paragraph (c) of this section, in determining whether an individual poses a direct threat, a recipient must make an individualized assessment, based on reasonable judgment that relies on current medical knowledge or on the best available objective evidence, to ascertain: the nature, duration, and severity of the risk; the probability that the potential injury will actually occur; and whether reasonable modifications of policies, practices, or procedures or the provision of auxiliary aids or services will mitigate the risk.

(c) In determining whether an individual poses a direct threat in employment, the recipient must make an individualized assessment according to the Equal Employment Opportunity Commission's regulation implementing title I of the Americans with Disabilities Act of 1990, at 29 CFR 1630.2(r).

§ 84.76 Integration.

(a) *Application.* This section applies to programs or activities that receive Federal financial assistance from the Department and to recipients that operate such programs or activities.

(b) *Discriminatory action prohibited.* A recipient shall administer a program or activity in the most integrated setting appropriate to the needs of a qualified person with a disability.

(c) *Segregated setting.* Segregated settings include but are not limited to congregate settings that are populated exclusively or primarily with individuals with disabilities and may be characterized by regimentation in daily activities; lack of privacy or autonomy; or policies or practices limiting visitors or limiting individuals' ability to engage freely in community activities and to manage their own activities of daily living.

(d) *Specific prohibitions.* The general prohibition in paragraph (b) of this section includes but is not limited to the following specific prohibitions, to the extent that such action results in unnecessary segregation, or serious risk of such segregation, of persons with disabilities.

(1) Establishing or applying policies or practices that limit or condition individuals with disabilities' access to the most integrated setting appropriate to their needs;

(2) Providing greater benefits or benefits under more favorable terms in segregated settings than in integrated settings;

(3) Establishing or applying more restrictive rules and requirements for qualified individuals with disabilities in integrated settings than for individuals with disabilities in segregated settings; or

(4) Failure to provide community-based services that results in institutionalization or serious risk of institutionalization. This paragraph (d)(4) includes, but is not limited to planning, service system design, funding, or service implementation practices that result in institutionalization or serious risk of institutionalization. Qualified individuals with disabilities need not wait until the harm of institutionalization or segregation occurs to assert their right to avoid unnecessary segregation.

(e) *Fundamental alteration.* A recipient may establish a defense to the application of this section if it can demonstrate that a requested modification would fundamentally alter the nature of its program or activity.

■ 34. Add subpart H, consisting of §§ 84.77 through 84.81, to read as follows:

Subpart H—Communications

Sec.
84.77 General.
84.78 Telecommunications.
84.79 Telephone emergency services.
84.80 Information and signage.
84.81 Duties.

Subpart H—Communications

§ 84.77 General.

(a)(1) A recipient shall take appropriate steps to ensure that communications with applicants, participants, members of the public, and companions with disabilities are as effective as communications with others.

(2) For purposes of this section, *companion* means a family member, friend, or associate of an individual seeking access to a program or activity of a recipient, who, along with such individual, is an appropriate person with whom the recipient should communicate.

(b)(1) The recipient shall furnish appropriate auxiliary aids and services where necessary to afford qualified individuals with disabilities, including applicants, participants, beneficiaries, companions, and members of the public, an equal opportunity to participate in, and enjoy the benefits of, a program or activity of a recipient.

(2) The type of auxiliary aid or service necessary to ensure effective communication will vary in accordance with the method of communication used by the individual; the nature, length, and complexity of the communication involved; and the context in which the communication is taking place. In determining what types of auxiliary aids and services are necessary, a recipient shall give primary consideration to the requests of individuals with disabilities. In order to be effective, auxiliary aids and services must be provided in accessible formats, in a timely manner, and in such a way as to protect the privacy and independence of the individual with a disability.

(c)(1) A recipient shall not require an individual with a disability to bring another individual to interpret for him or her.

(2) A recipient shall not rely on an adult accompanying an individual with a disability to interpret or facilitate communication except—

(i) In an emergency involving an imminent threat to the safety or welfare of an individual or the public where there is no interpreter available; or

(ii) When the individual with a disability specifically requests that the accompanying adult interpret or facilitate communication, the accompanying adult agrees to provide such assistance, and reliance on that adult for such assistance is appropriate under the circumstances.

(3) A recipient shall not rely on a minor child to interpret or facilitate communication, except in an emergency involving an imminent threat to the safety or welfare of an individual or the public when there is no interpreter available.

(d) When the recipient chooses to provide qualified interpreters via video remote interpreting services (VRI), it shall ensure that it provides—

(1) Real-time, full-motion video and audio over a dedicated high-speed, wide-bandwidth video connection or wireless connection that delivers high-quality video images that do not produce lags, choppy, blurry, or grainy images, or irregular pauses in communication;

(2) A sharply delineated image that is large enough to display the interpreter's face, arms, hands, and fingers, and the participating individual's face, arms, hands, and fingers, regardless of their body position;

(3) A clear, audible transmission of voices; and

(4) Adequate training to users of the technology and other involved individuals so that they may quickly and efficiently set up and operate the VRI.

§ 84.78 Telecommunications.

(a) Where a recipient communicates by telephone with applicants and beneficiaries, text telephones (TTYs) or equally effective telecommunications systems shall be used to communicate with individuals who are deaf or hard of hearing or have speech impairments.

(b) When a recipient uses an automated-attendant system, including, but not limited to, voice mail and messaging, or an interactive voice response system, for receiving and directing incoming telephone calls, that system must provide effective real-time communication with individuals using auxiliary aids and services, including TTYs and all forms of Federal Communications Commission (FCC)-approved telecommunications relay systems, including internet-based relay systems.

(c) A recipient shall respond to telephone calls from a telecommunications relay service established under title IV of the ADA in the same manner that it responds to other telephone calls.

§ 84.79 Telephone emergency services.

Telephone emergency services, including 911 services, shall provide direct access to individuals who use TTYs and computer modems.

§ 84.80 Information and signage.

(a) A recipient shall ensure that interested persons, including persons with impaired vision or hearing, can obtain information as to the existence and location of accessible services, activities, and facilities.

(b) A recipient shall provide signage at all inaccessible entrances to each of its facilities, directing users to an accessible entrance or to a location at which they can obtain information about accessible facilities. The international symbol for accessibility shall be used at each accessible entrance of a facility.

§ 84.81 Duties.

This subpart does not require a recipient to take any action that it can demonstrate would result in a fundamental alteration in the nature of a program or activity or undue financial and administrative burdens. In those circumstances where a recipient's personnel believe that the proposed action would fundamentally alter the program or activity or would result in undue financial and administrative burdens, the recipient has the burden of proving that compliance with this subpart would result in such alteration or burdens. The decision that compliance would result in such alteration or burdens must be made by the head of the recipient or their designee after considering all the recipient's resources available for use in the funding and operation of the program or activity and must be accompanied by a written statement of reasons for reaching that conclusion. If an action required to comply with this part would result in such an alteration or such burdens, the recipient shall take any other action that would not result in such an alteration or such burdens but would nevertheless ensure that, to the maximum extent possible, individuals with disabilities receive the benefits or services provided by the recipient.

■ 35. Add subpart I, consisting of §§ 84.82 through 84.89, to read as follows:

Subpart I—Web, Mobile, and Kiosk Accessibility

Sec.

84.82 Application.
84.83 Accessibility of kiosks.
84.84 Requirements for web and mobile accessibility.
84.85 Exceptions.
84.86 Conforming alternate versions.
84.87 Equivalent facilitation.
84.88 Duties.
84.89 Effect of noncompliance that has a minimal impact on access.

Subpart I—Web, Mobile, and Kiosk Accessibility

§ 84.82 Application.

This subpart applies to all programs or activities that receive Federal financial assistance from the Department.

§ 84.83 Accessibility of kiosks.

No qualified individual with a disability shall, on the basis of disability, be excluded from participation in, be denied the benefits of, or otherwise be subjected to discrimination under any program or activity of a recipient provided through kiosks.

§ 84.84 Requirements for web and mobile accessibility.

(a) *General.* A recipient shall ensure that the following are readily accessible to and usable by individuals with disabilities:

(1) Web content that a recipient provides or makes available, directly or through contractual, licensing, or other arrangements; and

(2) Mobile apps that a recipient provides or makes available, directly or through contractual, licensing, or other arrangements.

(b) *Requirements.* (1) Beginning May 11, 2026, a recipient with fifteen or more employees shall ensure that the web content and mobile apps that the recipient provides or makes available, directly or through contractual, licensing, or other arrangements, comply with Level A and Level AA success criteria and conformance requirements specified in WCAG 2.1, unless the recipient can demonstrate that compliance with this section would result in a fundamental alteration in the nature of a program or activity or in undue financial and administrative burdens.

(2) Beginning May 10, 2027, a recipient with fewer than fifteen employees shall ensure that the web content and mobile apps that the recipient provides or makes available, directly or through contractual, licensing, or other arrangements, comply with Level A and Level AA success criteria and conformance requirements specified in WCAG 2.1, unless the recipient can demonstrate that compliance with this section would result in a fundamental alteration in the nature of a program or activity or in undue financial and administrative burdens.

(3) WCAG 2.1 is incorporated by reference into this section with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All material approved for incorporation by reference (IBR) is available for inspection at HHS and at the National Archives and Records Administration (''NARA''). Contact HHS, OCR at: Office for Civil Rights, U.S. Department of Health and Human Services, 200 Independence Ave. SW, Room 509F, HHH Building, Washington, DC 20201; phone: (202) 545–4884; email: *504@hhs.gov.* For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations* or email *fr.inspection@nara.gov.* The material may be obtained from the World Wide Web Consortium (W3C) Web Accessibility Initiative (''WAI''), 401 Edgewater Place, Suite 600, Wakefield, MA 01880; phone: (339) 273–2711; email: *contact@w3.org;* website: *www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F.*

§ 84.85 Exceptions.

The requirements of § 84.84 do not apply to the following:

(a) *Archived web content.* Archived web content as defined in § 84.10.

(b) *Preexisting conventional electronic documents.* Conventional electronic documents that are available as part of a recipient's web content or mobile apps before the date the recipient is required to comply with § 84.84, unless such documents are currently used to apply for, gain access to, or participate in the recipient's programs or activities.

(c) *Content posted by a third party.* Content posted by a third party, unless the third party is posting due to contractual, licensing, or other arrangements with the recipient.

(d) *Individualized, password-protected documents or otherwise secured conventional electronic documents.* Conventional electronic documents that are:

(1) About a specific individual, their property, or their account; and

(2) Password-protected or otherwise secured.

(e) *Preexisting social media posts.* A recipient's social media posts that were posted before the date the recipient is required to comply with § 84.84.

§ 84.86 Conforming alternate versions.

(a) A recipient may use conforming alternate versions of web content, as defined by WCAG 2.1, to comply with § 84.84 only where it is not possible to

make web content directly accessible due to technical or legal limitations.

(b) WCAG 2.1 is incorporated by reference into this section with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All material approved for incorporation by reference is available for inspection at HHS and at NARA. Contact HHS, OCR at: Office for Civil Rights, U.S. Department of Health and Human Services, 200 Independence Ave. SW, Room 509F, HHH Building, Washington, DC 20201; phone: (202) 545–4884; email: *504@hhs.gov.* For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations* or email *fr.inspection@nara.gov.* The material may be obtained from the World Wide Web Consortium (W3C) Web Accessibility Initiative (''WAI''), 401 Edgewater Place, Suite 600, Wakefield, MA 01880; phone: (339) 273–2711; email: *contact@w3.org;* website: *www.w3.org/TR/2018/REC-WCAG21-20180605/* and *https://perma.cc/UB8A-GG2F.*

§ 84.87 Equivalent facilitation.

Nothing in this subpart prevents the use of designs, methods, or techniques as alternatives to those prescribed, provided that the alternative designs, methods, or techniques result in substantially equivalent or greater accessibility and usability of the web content or mobile app.

§ 84.88 Duties.

Where a recipient can demonstrate that compliance with the requirements of § 84.84 would result in a fundamental alteration in the nature of a program or activity or in undue financial and administrative burdens, compliance with § 84.84 is required to the extent that it does not result in a fundamental alteration or undue financial and administrative burdens. In those circumstances where personnel of the recipient believe that the proposed action would fundamentally alter the program or activity or would result in undue financial and administrative burdens, a recipient has the burden of proving that compliance with § 84.84 would result in such alteration or burdens. The decision that compliance would result in such alteration or burdens must be made by the head of a recipient or their designee after considering all resources available for use in the funding and operation of the program or activity, and must be accompanied by a written statement of the reasons for reaching that conclusion. If an action would result in such an alteration or such burdens, a recipient shall take any other action that would not result in such an alteration or such burdens but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient to the maximum extent possible.

§ 84.89 Effect of noncompliance that has a minimal impact on access.

A recipient that is not in full compliance with the requirements of § 84.84(b) will be deemed to have met the requirements of § 84.84 in the limited circumstance in which the recipient can demonstrate that the noncompliance has such a minimal impact on access that it would not affect the ability of individuals with disabilities to use the recipient's web content or mobile app to do any of the following in a manner that provides substantially equivalent timeliness, privacy, independence, and ease of use:

(a) Access the same information as individuals without disabilities;

(b) Engage in the same interactions as individuals without disabilities;

(c) Conduct the same transactions as individuals without disabilities; and

(d) Otherwise participate in or benefit from the same programs and activities as individuals without disabilities.

■ 36. Add subpart J, consisting of §§ 84.90 through 84.97, to read as follows:

Subpart J—Accessible Medical Equipment

Sec.

84.90 Application.
84.91 Requirements for medical diagnostic equipment.
84.92 Newly purchased, leased, or otherwise acquired medical diagnostic equipment.
84.93 Existing medical diagnostic equipment.
84.94 Qualified staff.
84.95–84.97 [Reserved]

Subpart J—Accessible Medical Equipment

§ 84.90 Application.

This subpart applies to programs or activities that receive Federal financial assistance from the Department and to recipients that operate, or that receive Federal financial assistance for the operation of, such programs or activities.

§ 84.91 Requirements for medical diagnostic equipment.

No qualified individual with a disability shall, on the basis of disability, be excluded from participation in, be denied the benefits of the programs or activities of a recipient offered through or with the use of medical diagnostic equipment (MDE), or otherwise be subjected to discrimination under any program or activity that receives Federal financial assistance because the recipient's MDE is not readily accessible to or usable by persons with disabilities.

§ 84.92 Newly purchased, leased, or otherwise acquired medical diagnostic equipment.

(a) *Requirements for all newly purchased, leased, or otherwise acquired medical diagnostic equipment.* All MDE that recipients purchase, lease (including via lease renewals), or otherwise acquire more than July 8, 2024, subject to the requirements and limitations set forth in this section, meet the Standards for Accessible MDE, unless and until the recipient satisfies the scoping requirements set forth in paragraph (b) of this section.

(b) *Scoping requirements*—(1) *General requirement for medical diagnostic equipment.* Where a program or activity of a recipient, including physicians' offices, clinics, emergency rooms, hospitals, outpatient facilities, and multi-use facilities, utilizes MDE, at least 10 percent of the total number of units, but no fewer than one unit, of each type of equipment in use must meet the Standards for Accessible MDE.

(2) *Facilities that specialize in treating conditions that affect mobility.* In rehabilitation facilities that specialize in treating conditions that affect mobility, outpatient physical therapy facilities, and other programs or activities that specialize in treating conditions that affect mobility, at least 20 percent, but no fewer than one unit, of each type of equipment in use must meet the Standards for Accessible MDE.

(3) *Facilities with multiple departments.* In any facility or program with multiple departments, clinics, or specialties, where a program or activity uses MDE, the facility shall disperse the accessible MDE required by paragraphs (b)(1) and (2) of this section in a manner that is proportionate by department, clinic, or specialty using MDE.

(c) *Requirements for examination tables and weight scales.* Within 2 years after July 8, 2024, recipients shall, subject to the requirements and limitations set forth in this section, purchase, lease, or otherwise acquire the following, unless the recipient already has them in place:

(1) At least one examination table that meets the Standards for Accessible MDE, if the recipient uses at least one examination table; and

(2) At least one weight scale that meets the Standards for Accessible MDE, if the recipient uses at least one weight scale.

(d) *Equivalent facilitation.* Nothing in this section prevents the use of designs, products, or technologies as alternatives to those prescribed by the Standards for Accessible MDE, provided they result in substantially equivalent or greater accessibility and usability of the program or activity. The responsibility for demonstrating equivalent facilitation rests with the recipient.

(e) *Fundamental alteration and undue burdens.* This section does not require a recipient to take any action that it can demonstrate would result in a fundamental alteration in the nature of a program or activity, or in undue financial and administrative burdens. In those circumstances where personnel of the recipient believe that the proposed action would fundamentally alter the program or activity or would result in undue financial and administrative burdens, a recipient has the burden of proving that compliance with paragraph (a) or (c) of this section would result in such alteration or burdens. The decision that compliance would result in such alteration or burdens must be made by the head of a recipient or their designee after considering all resources available for use in the funding and operation of the program or activity and must be accompanied by a written statement of the reasons for reaching that conclusion. If an action would result in such an alteration or such burdens, a recipient shall take any other action that would not result in such an alteration or such burdens but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient.

(f) *Diagnostically required structural or operational characteristics.* A recipient meets its burden of proving that compliance with paragraph (a) or (c) of this section would result in a fundamental alteration under paragraph (e) of this section if it demonstrates that compliance with paragraph (a) or (c) would alter diagnostically required structural or operational characteristics of the equipment, and prevent the use of the equipment for its intended diagnostic purpose. This paragraph (f) does not excuse compliance with other technical requirements where compliance with those requirements does not prevent the use of the equipment for its diagnostic purpose.

§ 84.93 Existing medical diagnostic equipment.

(a) *Accessibility.* A recipient shall operate each program or activity offered through or with the use of MDE so that the program or activity, in its entirety, is readily accessible to and usable by individuals with disabilities. This paragraph (a) does not—

(1) Necessarily require a recipient to make each of its existing pieces of medical diagnostic equipment accessible to and usable by individuals with disabilities; or

(2) Require a recipient to take any action that it can demonstrate would result in a fundamental alteration in the nature of a program or activity, or in undue financial and administrative burdens. In those circumstances where personnel of the recipient believe that the proposed action would fundamentally alter the program or activity or would result in undue financial and administrative burdens, a recipient has the burden of proving that compliance with this paragraph (a) would result in such alteration or burdens. The decision that compliance would result in such alteration or burdens must be made by the head of the recipient or their designee after considering all resources available for use in the funding and operation of the program or activity and must be accompanied by a written statement of the reasons for reaching that conclusion. If an action would result in such an alteration or such burdens, the recipient shall take any other action that would not result in such an alteration or such burdens but would nevertheless ensure that individuals with disabilities receive the benefits or services provided by the recipient.

(3) A recipient meets its burden of proving that compliance with this paragraph (a) would result in a fundamental alteration under paragraph (a)(2) of this section if it demonstrates that compliance with this paragraph (a) would alter diagnostically required structural or operational characteristics of the equipment, and prevent the use of the equipment for its intended diagnostic purpose.

(b) *Methods.* A recipient may comply with the requirements of this section through such means as reassignment of services to alternate accessible locations, home visits, delivery of services at alternate accessible sites, purchase, lease, or other acquisition of accessible MDE, or any other methods that result in making its programs or activities readily accessible to and usable by individuals with disabilities. A recipient is not required to purchase, lease, or otherwise acquire accessible medical diagnostic equipment where other methods are effective in achieving compliance with this section. In choosing among available methods for meeting the requirements of this section, a recipient shall give priority to those methods that offer programs and activities to qualified individuals with disabilities in the most integrated setting appropriate.

§ 84.94 Qualified staff.

Recipients must ensure their staff are able to successfully operate accessible MDE, assist with transfers and positioning of individuals with disabilities, and carry out the program access obligation regarding existing MDE.

§§ 84.95–84.97 [Reserved]

■ 37. Add subpart K, consisting of § 84.98, to read as follows:

Subpart K—Procedures

§ 84.98 Procedures.

The procedural provisions applicable to title VI of the Civil Rights Act of 1964 apply to this part. These procedures are found in 45 CFR 80.6 through 80.10 and 45 CFR part 81.

Xavier Becerra,

Secretary, Department of Health and Human Services.

[FR Doc. 2024–09237 Filed 5–1–24; 8:45 am]

BILLING CODE 4165–16–P

FEDERAL REGISTER

Vol. 89 Thursday,
No. 91 May 9, 2024

Part V

Environmental Protection Agency

40 CFR Part 423
Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 423

[EPA–HQ–OW–2009–0819; FRL–8794–02–OW]

RIN 2040–AG23

Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA or the Agency) is finalizing a Clean Water Act regulation to revise the technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category applicable to flue gas desulfurization (FGD) wastewater, bottom ash (BA) transport water and legacy wastewater at existing sources, and combustion residual leachate (CRL) at new and existing sources. Last updated in 2015 and 2020, this regulation is estimated to cost an additional $536 million to $1.1 billion dollars annually in social costs and reduce pollutant discharges by an additional approximately 660 to 672 million pounds per year.

DATES: This final rule is effective on July 8, 2024. In accordance with 40 CFR part 23, this regulation shall be considered issued for purposes of judicial review at 1 p.m. Eastern time on May 23, 2024. Under section 509(b)(1) of the Clean Water Act (CWA), judicial review of this regulation can be had only by filing a petition for review in the U.S. Court of Appeals within 120 days after the regulation is considered issued for purposes of judicial review. Under section 509(b)(2), the requirements of this regulation may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OW–2009–0819. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed in the index, some information listed in the index is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: For technical information, contact Richard Benware, Engineering and Analysis Division, telephone: 202–566–1369; email: *benware.richard@epa.gov.* For economic information, contact James Covington, Water Economics Center, telephone: 202–566–1034; email: *covington.james@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble Acronyms and Abbreviations. The EPA uses multiple acronyms and terms in this preamble. To ease the reading of this preamble and for reference purposes, the EPA defines terms and abbreviations used in appendix A (although the list of abbreviations in the appendix is not exhaustive).

Supporting Documentation. The rule is supported by several documents, including the following:

- *Technical Development Document for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (TDD), Document No. 821R24004. This report summarizes the technical and engineering analyses supporting the rule. The TDD presents the EPA's updated analyses supporting the revisions to FGD wastewater, BA transport water, CRL, and legacy wastewater. The TDD includes additional data that has been collected since the publication of the 2015 and 2020 rules, updates to the industry (*e.g.,* retirements, updates to wastewater handling), cost methodologies, pollutant removal estimates, non-water quality environmental impacts associated with updated FGD and BA methodologies, and calculations for the effluent limitations. In addition to the TDD, the Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (2015 TDD, Document No. EPA–821–R–15–007) and the Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (2020 Supplemental TDD, Document No. EPA–821–R–20–001) provide a more complete summary of the EPA's data collection, description of the industry, and underlying analyses supporting the 2015 and 2020 rules.
- *Environmental Assessment for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (EA),* Document No. 821R24005. This report summarizes the potential environmental and human health impacts estimated to result from implementation of the revisions to the 2015 and 2020 rules.
- *Benefit and Cost Analysis for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (BCA), Document No. 821R24006. This report summarizes the societal benefits and costs estimated to result from implementation of the revisions to the 2015 and 2020 rules.
- *Regulatory Impact Analysis for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (RIA), Document No. 821R24007. This report presents a profile of the steam electric power generating industry, a summary of estimated costs and impacts associated with the revisions to the 2015 and 2020 rules, and an assessment of the potential impacts on employment and small businesses.
- *Environmental Justice Analysis for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EJA), Document No. 821R24008. This report presents a profile of the communities and populations potentially impacted by this rule, an analysis of the distribution of impacts in the baseline scenario and with the revisions, and a summary of inputs from potentially impacted communities that the EPA met with prior to publishing the proposed rulemaking.
- *Docket Index for the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.* This document provides a list of additional memoranda, references, and other information the EPA relied on for the final revisions to the ELGs.

Organization of this Document. The information in this preamble is organized as follows:

Table of Contents

I. Executive Summary
  A. Purpose of Rule
II. Public Participation
III. General Information
  A. Does this action apply to me?
  B. What action is the EPA taking?
  C. What is EPA's authority for taking this action?
  D. What are the monetized incremental costs and benefits of this action?
IV. Background
  A. Clean Water Act
  B. Relevant Effluent Guidelines
  C. 2015 Steam Electric Power Generation Point Source Category Rule
  D. 2020 Steam Electric Reconsideration Rule and Recent Developments

E. Other Ongoing EPA Rules Impacting the Steam Electric Sector
V. Steam Electric Power Generating Industry Description
A. General Description of Industry
B. Current Market Conditions and Drivers in the Electricity Generation Sector
C. Control and Treatment Technologies
VI. Data Collection Since the 2020 Rule
A. Information from the Electric Utility Industry
B. Notices of Planned Participation
C. Information from Technology Vendors and Engineering, Procurement, and Construction Firms
D. Other Data Sources
VII. Final Regulation
A. Description of the Options
B. Rationale for the Final Rule
C. Subcategories
D. Additional Rationale for the Proposed PSES and PSNS
E. Availability Timing of New Requirements
F. Economic Achievability
G. Non-Water Quality Environmental Impacts
H. Impacts on Residential Electricity Prices and Communities with Environmental Justice Concerns
VIII. Costs, Economic Achievability, and Other Economic Impacts
A. Plant-Specific and Industry Total Costs
B. Social Costs
C. Economic Impacts
IX. Pollutant Loadings
A. FGD Wastewater
B. BA Transport Water
C. CRL
D. Legacy Wastewater
E. Summary of Incremental Changes of Pollutant Loadings from the Final Rule
X. Non-Water Quality Environmental Impacts
A. Energy Requirements
B. Air Pollution
C. Solid Waste Generation and Beneficial Use
D. Changes in Water Use
XI. Environmental Assessment
A. Introduction
B. Updates to the Environmental Assessment Methodology
C. Outputs from the Environmental Assessment
XII. Benefits Analysis
A. Categories of Benefits Analyzed
B. Quantification and Monetization of Benefits
C. Total Monetized Benefits
D. Additional Benefits
XIII. Environmental Justice Impacts
A. Literature Review
B. Proximity Analysis
C. Community Outreach
D. Distribution of Risks
E. Distribution of Benefits and Costs
XIV. Regulatory Implementation
A. Continued Implementation of Existing Limitations and Standards
B. Implementation of New Limitations and Standards
C. Reporting and Recordkeeping Requirements
D. Site-Specific Water Quality-Based Effluent Limitations
E. Severability
XV. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review
B. Paperwork Reduction Act (PRA)
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All
K. Congressional Review Act (CRA)
Appendix A to the Preamble: Definitions, Acronyms, and Abbreviations Used in This Preamble

I. Executive Summary

A. Purpose of Rule

The EPA is promulgating this final supplemental rule to update requirements that apply to wastewater discharges from steam electric power plants, particularly coal-fired power plants. In 2015, the EPA set the first Federal limitations on the levels of toxic metals in several of the largest sources of wastewater that can be discharged from power plants after last updating these regulations in 1982 (80 **Federal Register** (FR) 67838; November 3, 2015) (hereinafter the ''2015 rule''). On an annual basis, the 2015 rule was projected to reduce the amount of toxic metals, nutrients, and other pollutants that steam electric power plants are allowed to discharge by 1.4 billion pounds and reduce water withdrawal by 57 billion gallons. This rule was reconsidered in 2020 and modified in part due to changing dynamics in the power sector (85 FR 64650; October 13, 2020) (hereinafter the ''2020 rule''). Steam electric power plants are increasingly aging and less competitive sources of electric power in many portions of the United States.

Steam electric power plants, coal-fired power plants in particular, are subject to several environmental regulations designed to control (and in some cases eliminate) air, water, and land pollution over time. This rule, the Steam Electric Power Generating Effluent Limitations Guidelines and Standards—or steam electric ELGs—applies to the subset of the electric power industry where ''generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel (*e.g.,* coal, oil, gas), fuel derived from fossil fuel (*e.g.,* petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam-water system as the thermodynamic medium'' (40 Code of Federal Regulations (CFR) 423.10). The 2015 rule addressed discharges from FGD wastewater, fly ash (FA) transport water, BA transport water, flue gas mercury control (FGMC) wastewater, gasification wastewater, CRL, legacy wastewater, and nonchemical metal cleaning wastes. The 2020 rule modified the 2015 requirements for FGD wastewater and BA transport water for existing sources only. The 2015 limitations for CRL from existing sources and legacy wastewater were vacated by the United States (U.S.) Court of Appeals for the Fifth Circuit in *Southwestern Electric Power Co., et al.* v. *EPA,* 920 F.3d 999 (5th Cir. 2019).

In the years since the EPA revised the steam electric ELGs in 2015 and 2020, new information has become available, which the EPA considered in finalizing this supplemental rule. For example, pilot testing and full-scale use of various, better performing treatment technologies have continued to develop, along with more data and information about their performance. The final supplemental rule updates requirements for discharges from two wastestreams addressed in the 2020 rule: BA transport water and FGD wastewater at existing sources. The final supplemental rule also replaces the court-vacated limitations for CRL (except for CRL discharges in one subcategory) and a subcategory of legacy wastewater. Finally, for the remaining CRL and legacy wastewaters, this rule finalizes a site-specific approach to developing technology-based limitations based on the permitting authorities' best professional judgment (BPJ), an option discussed by the Court in *Southwestern Electric Power Co.* v. *EPA.*

B. Summary of Final Rule

For existing sources that discharge directly to surface water, with the exception of the subcategories discussed below, the final rule establishes the following effluent limitations based on Best Available Technology Economically Achievable (BAT):

- A zero-discharge limitation for all pollutants in FGD wastewater, BA transport water, and CRL.

• Numeric (nonzero) discharge limitations for mercury and arsenic in unmanaged CRL [1] and for legacy wastewater discharged from surface impoundments during the closure process if those surface impoundments have not commenced closure under the Coal Combustion Residuals (CCR) regulations as of the effective date of this rule.

The final rule eliminates the separate, 2020 rule's less stringent BAT requirements for two subcategories: high-flow facilities and low-utilization electric generating units (LUEGUs), except to the extent they apply to one new permanent cessation of coal combustion subcategory. The final rule leaves in place the existing subcategories for oil-fired and small (50 megawatts (MW) or less) electric generating units (EGUs) established in the 2015 rule. The final rule also leaves in place the existing subcategory for EGUs permanently ceasing the combustion of coal by 2028, which was established in the 2020 rule and amended in a 2023 direct final rule by extending the date for filing a Notice of Planned Participation (NOPP). *See* 88 FR 18440 (March 29, 2023). Lastly, the final rule creates a new subcategory for EGUs permanently ceasing coal combustion by 2034. For both the existing and new subcategories referenced immediately above, the EPA is finalizing additional reporting and recordkeeping requirements and zero-discharge limitations applicable after EGUs cease coal combustion, as well as procedural requirements for affected facilities to demonstrate permanent cessation of coal combustion or that permanent retirement will occur.

As stated above, the rule eliminates the 2020 rule subcategories for high flow and low utilization, except to the extent they apply to EGUs in the new permanent cessation of coal combustion by 2034 subcategory. The elimination of the 2020 rule's subcategories will affect the one known high-flow facility (the Tennessee Valley Authority (TVA) Cumberland Fossil Plant) that has indicated it is planning to close and the two known facilities with LUEGUs (GSP Merrimack LLC and Indiana Municipal Power Agency (IMPA) Whitewater Valley Station), one of which is also expected to close. For EGUs ceasing coal combustion by 2034, the final rule retains the 2020 rule requirements for FGD wastewater and BA transport water and the pre-2015 BPJ-based BAT requirements for CRL rather than requiring the new, more stringent zero-discharge requirements for these wastestreams. After the permanent cessation of coal combustion, however, EGUs in this subcategory must meet limitations on arsenic and mercury based on chemical precipitation for CRL.

Where BAT limitations in this final rule are more stringent than previously established Best Practicable Control Technology Currently Available (BPT) and BAT limitations, any new limitations for direct dischargers do not apply until a date determined by the permitting authority that is as soon as possible on or after July 8, 2024, but no later than December 31, 2029.

For indirect discharges (*i.e.,* discharges to publicly owned treatment works (POTWs)), the final rule establishes pretreatment standards for existing sources that are the same as the BAT limitations except where limitations are for total suspended solids (TSS), a pollutant that does not pass through POTWs. Pretreatment standards are directly enforceable and apply May 9, 2027.

While the EPA is not aware of any planned new sources that would be subject to the requirements of this final supplement rule, this action sets new source performance standards and pretreatment standards for discharges of CRL from new sources that are equivalent to the new BAT limitations—namely, zero discharge.

C. Summary of Costs and Benefits

The EPA estimates that the final rule will cost $536 million to $1.1 billion per year in social costs and result in $3.2 billion per year in monetized benefits using a 2 percent discount rate.[2]

The EPA's analysis reflects the Agency's understanding of the actions steam electric power plants are expected to take to meet the limitations and standards in the final rule, including the implementation of additional treatment technologies to reduce pollutant discharges. The EPA based its analysis on a modeled baseline that reflects the full implementation of the 2020 rule, the expected effects of announced retirements and fuel conversions, and the anticipated impacts of relevant final rules affecting the power sector. Not all costs and benefits can be fully quantified and monetized. While some health benefits and willingness to pay (WTP) for water quality improvements have been quantified and monetized, those estimates may not fully capture all important water-quality-related benefits. Furthermore, the EPA anticipates the final rule would generate important additional benefits that the Agency was only able to analyze qualitatively (*e.g.,* improved habitat conditions for plants, invertebrates, fish, amphibians, and the wildlife that prey on aquatic organisms).

For additional information on costs and benefits, *see* sections VIII and XII of this preamble, respectively.

II. Public Participation

During the 60-day public comment period on the 2023 proposed supplemental rule (88 FR 18824, March 29, 2023) (from March 29, 2023, to May 30, 2023), the EPA received more than 22,000 public comment submissions from private citizens, industry representatives, technology vendors, government entities, environmental groups, and trade associations. The EPA also hosted two online public hearings during the public comment period—one on April 20, 2023, and one on April 25, 2023. These hearings had a combined total of 196 attendees, 46 of whom registered to provide comment on the proposed rule. Available documents from each public hearing include the presentations given by the EPA and two transcripts (document control number (DCN) SE10469, DCN SE10469A1, DCN SE10470 and DCN SE10470A1).

III. General Information

A. Does this action apply to me?

Entities potentially regulated by any final rule following this action include the following:

[1] As discussed in section VII.C.5 of this document, the EPA is defining unmanaged CRL in this rule to mean CRL which either: (1) the permitting authority determines are the functional equivalent of a direct discharge to waters of the United States (WOTUS) through groundwater or (2) CRL that has leached from a waste management unit into the subsurface and mixed with groundwater prior to being captured and pumped to the surface for discharge directly to a WOTUS.

[2] The EPA estimated the annualized value of future benefits and costs using a discount rate of 2 percent, following current Office of Management and Budget (OMB) guidance in Circular A–4 (OMB, 2023). In appendix B of the BCA, the EPA also provides results of analyses performed using 3 percent and 7 percent discount rates to allow comparison of the final rule costs and benefits with those estimated at proposal, which followed the guidance applicable at the time the prior analysis was conducted (OMB, 2003).

Category	Example of regulated entity	North American Industry Classification System (NAICS) Code
Industry	Electric Power Generation Facilities—Electric Power Generation	22111
	Electric Power Generation Facilities—Fossil Fuel Electric Power Generation	221112

This section is not intended to be exhaustive, but rather provides a guide regarding entities likely to be regulated by this final rule. Other types of entities that do not meet the above criteria could also be regulated. To determine whether a specific facility is regulated by this final rule, carefully examine the applicability criteria listed in 40 CFR 423.10 and the definitions in 40 CFR 423.11. If you still have questions regarding the applicability of this final rule to a particular entity, consult the person listed for technical information in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What action is the EPA taking?

The Agency is revising certain BAT ELGs for existing sources in the steam electric power generating point source category that apply to FGD wastewater, BA transport water, CRL, and legacy wastewater.

C. What is EPA's authority for taking this action?

The EPA is finalizing this rule under the authority of sections 301, 304, 306, 307, 308, 402, and 501 of the CWA, 33 United States Code (U.S.C.) 1311, 1314, 1316, 1317, 1318, 1342, and 1361.

D. What are the monetized incremental costs and benefits of this action?

This final rule is estimated to have social costs of $536 million to $1.1 billion per year and result in $3.2 billion in benefits using a two percent discount rate.[3]

IV. Background

A. Clean Water Act

Congress passed the Federal Water Pollution Control Act Amendments of 1972, also known as the CWA, to ''restore and maintain the chemical, physical, and biological integrity of the Nation's waters.'' 33 U.S.C. 1251(a). The CWA establishes a comprehensive program for protecting our nation's waters. Among its core provisions, the CWA prohibits the discharge of pollutants from a point source to waters of the United States (WOTUS), except as authorized under the CWA. Under section 402 of the CWA, discharges may be authorized through a National Pollutant Discharge Elimination System (NPDES) permit. The CWA also authorizes the EPA to establish nationally applicable, technology-based ELGs for discharges from different categories of point sources, such as industrial, commercial, and public sources.

Furthermore, the CWA authorizes the EPA to promulgate nationally applicable pretreatment standards that restrict pollutant discharges from facilities that discharge wastewater to WOTUS indirectly through sewers flowing to POTWs, as outlined in CWA sections 307(b) and (c), 33 U.S.C. 1317(b) and (c). The EPA establishes national pretreatment standards for those pollutants in wastewater from indirect dischargers that may pass through, interfere with, or are otherwise incompatible with POTW operations. Pretreatment standards are designed to ensure that wastewaters from direct and indirect industrial dischargers are subject to similar levels of treatment. *See* CWA section 301(b), 33 U.S.C. 1311(b); *Chem. Mfrs. Ass'n* v. *NRDC,* 470 U.S. 116, 119 (1985); *Envtl. Def. Fund* v. *Costle,* 636 F.2d 1229, 1235 n.15 (D.C. Cir. 1980); *Reynolds Metals Co.* v. *EPA,* 760 F.2d 549, 553 (4th Cir. 1985); *Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d 177, 249 (5th Cir. 1989). In addition, POTWs are required to implement local treatment limitations applicable to their industrial indirect dischargers to satisfy any local requirements. *See* 40 CFR 403.5.

Direct dischargers (*i.e.,* those discharging directly from a point source to surface waters rather than through POTWs) must comply with effluent limitations in NPDES permits. Discharges that flow through groundwater before reaching surface waters must also comply with effluent limitations in NPDES permits if those discharges are the ''functional equivalent'' of a direct discharge from a point source to a WOTUS. *County of Maui* v. *Hawaii Wildlife Fund,* 590 U.S. 165 (2020). Indirect dischargers, who discharge through POTWs, must comply with pretreatment standards. Technology-based effluent limitations in NPDES permits are derived from ELGs (CWA sections 301 and 304, 33 U.S.C. 1311 and 1314) and new source performance standards (CWA section 306, 33 U.S.C. 1316) promulgated by the EPA, or based on BPJ where the EPA has not promulgated an applicable effluent guideline or new source performance standard. CWA section 402(a)(1)(B), 33 U.S.C. 1342(a)(1)(B); 40 CFR 125.3(c). Additional limitations based on water quality standards are also required to be included in the permit in certain circumstances. CWA section 301(b)(1)(C), 33 U.S.C. 1311(b)(1)(C); 40 CFR 122.44(d). The EPA establishes ELGs by regulation for categories of point source dischargers, and these ELGs are based on the degree of control that can be achieved using various levels of pollution control technology.

The EPA promulgates national ELGs for major industrial categories for three classes of pollutants: (1) conventional pollutants (*i.e.,* TSS, oil and grease, biochemical oxygen demand (BOD_5), fecal coliform, and pH), as outlined in CWA section 304(a)(4) and 40 CFR 401.16; (2) toxic pollutants (*e.g.,* toxic metals such as arsenic, mercury, selenium, and chromium; toxic organic pollutants such as benzene, benzo-a-pyrene, phenol, and naphthalene), as outlined in section 307(a) of the Act, 40 CFR 401.15 and 40 CFR part 423, appendix A; and (3) nonconventional pollutants, which are those pollutants that are not categorized as conventional or toxic (*e.g.,* ammonia-N, phosphorus, total dissolved solids (TDS)).

B. Relevant Effluent Guidelines

The EPA develops effluent guidelines that are technology-based regulations for a category of dischargers. The EPA bases these regulations on the performance of control and treatment technologies. The legislative history of CWA section 304(b), which is the heart of the effluent guidelines program, describes the need to press toward higher levels of control through research and development of new processes, modifications, replacement of obsolete plants and processes, and other improvements in technology, while also accounting for the cost of controls. Legislative history and case law support that the EPA need

[3] See note 2.

not consider water quality impacts on individual water bodies as the guidelines are developed; *see* Statement of Senator Muskie (October 4, 1972), reprinted in Legislative History of the Water Pollution Control Act Amendments of 1972, at 170. (U.S. Senate, Committee on Public Works, Serial No. 93–1, January 1973); *see also Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1005 (''The Administrator must require industry, regardless of a discharge's effect on water quality, to employ defined levels of technology to meet effluent limitations.'') (citations and internal quotations omitted).

There are many technology-based effluent limitations (TBELs) that may apply to a discharger under the CWA: four types of standards applicable to direct dischargers, two types of standards applicable to indirect dischargers, and a default site-specific approach. The TBELs relevant to this rulemaking are described in detail below.

1. Best Practicable Control Technology Currently Available

Traditionally, the EPA defines Best Practicable Control Technology (BPT) effluent limitations based on the average of the best performances of facilities within the industry, grouped to reflect various ages, sizes, processes, or other common characteristics. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F3d at 1025. The EPA may promulgate BPT effluent limitations for conventional, toxic, and nonconventional pollutants. In specifying BPT, the EPA looks at several factors. The EPA considers the cost of achieving effluent reductions in relation to the effluent reduction benefits. The Agency also considers the age of equipment and facilities, the processes employed, engineering aspects of the control technologies, any required process changes, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate. CWA section 304(b)(1)(B), 33 U.S.C. 1314(b)(1)(B). If, however, existing performance is uniformly inadequate, the EPA may establish limitations based on higher levels of control than what is currently in place in an industrial category, when based on an agency determination that the technology is available in another category or subcategory and can be practicably applied.

2. Best Available Technology Economically Achievable

BAT represents the second level of stringency for controlling direct discharge of toxic and nonconventional pollutants. Courts have referred to this as the CWA's ''gold standard'' for controlling discharges from existing sources. *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1003; *see also Kennecott* v. *EPA,* 780 F.2d 445, 448 (4th Cir. 1985) (''The BAT standard reflects the intention of Congress to use the latest scientific research and technology in setting effluent limits, pushing industries toward the goal of zero discharge as quickly as possible.''). In general, BAT represents the best available, economically achievable performance of facilities in the industrial subcategory or category. As the statutory phrase intends, the EPA considers the technological availability and the economic achievability when determining what level of control represents BAT. CWA section 301(b)(2)(A), 33 U.S.C. 1311(b)(2)(A). Other statutory factors that the EPA considers in assessing BAT are the cost of achieving BAT effluent reductions, the age of equipment and facilities involved, the process employed, potential process changes, and non-water quality environmental impacts, including energy requirements, and such other factors as the Administrator deems appropriate. CWA section 304(b)(2)(B), 33 U.S.C. 1314(b)(2)(B). The Agency retains considerable discretion in assigning the weight to be accorded these factors. *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1045 (D.C. Cir. 1978). The EPA usually determines economic achievability based on the effect the cost of compliance with BAT limitations has on overall industry and subcategory financial conditions.

BAT reflects the highest performance in the industry and may reflect a higher level of performance than is currently being achieved based on technology transferred from a different subcategory or category, bench scale or pilot plant studies, or foreign plants. *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1006; *Chem. Mfrs. Ass'n* v. EPA, 870 F.2d at 226; *Nat. Res. Def. Council* v. *EPA,* 863 F.2d 1420, 1426 (9th Cir. 1988); *American Paper Inst.* v. *Train,* 543 F.2d 328, 353 (D.C. Cir. 1976); *American Frozen Food Inst.* v. *Train,* 539 F.2d 107, 132 (D.C. Cir. 1976). BAT may be based upon process changes or internal controls, even when these technologies are not common industry practice. *See American Frozen Foods,* 539 F.2d at 132, 140; *Reynolds Metals Co.* v. *EPA,* 760 F.2d at 562; *California & Hawaiian Sugar Co.* v. *EPA,* 553 F.2d 280, 285–88 (2nd Cir. 1977). ''In setting BAT, EPA uses not the average plant, but the optimally operating plant, the pilot plant which acts as a beacon to show what is possible.'' *Kennecott* v. *EPA,* 780 F.2d at 448 (citing *A Legislative History of the Water Pollution Control Act Amendments of 1972,* 93d Cong., 1st Sess. (Comm. Print 1973), at 798). As recently reiterated by the U.S. Court of Appeals for the Fifth Circuit, ''Under our precedent, a technological process can be deemed available for BAT purposes even if it is not in use at all, or if it is used in unrelated industries. Such an outcome is consistent with Congress'[s] intent to push pollution control technology.'' *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1031 (citation and internal quotations omitted); *see also Am. Petroleum Inst.* v. *EPA,* 858 F.2d 261, 265 (5th Cir. 1988).

3. New Source Performance Standards

New Source Performance Standards (NSPS) reflect effluent reductions that are achievable based on the Best Available Demonstrated Control Technology (BADCT). Owners of new facilities have the opportunity to install the best and most efficient production processes and wastewater treatment technologies. As a result, NSPS should represent the most stringent controls attainable through the application of the BADCT for all pollutants (that is, conventional, nonconventional, and toxic pollutants). In establishing NSPS, the EPA is directed to take into consideration the cost of achieving the effluent reduction and any non-water quality environmental impacts and energy requirements. CWA section 306(b)(1)(B), 33 U.S.C. 1316(b)(1)(B).

4. Pretreatment Standards for Existing Sources

Section 307(b), 33 U.S.C. 1317(b), of the CWA calls for the EPA to issue pretreatment standards for discharges of pollutants to POTWs. Pretreatment standards for existing sources (PSES) are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards are technology-based and are analogous to BPT and BAT ELGs; thus, the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT. The General Pretreatment Regulations, which set forth the framework for the implementation of categorical pretreatment standards, are found at 40 CFR part 403. These regulations establish pretreatment standards that apply to all non-domestic dischargers. *See* 52 FR 1586 (January 14, 1987).

5. Pretreatment Standards for New Sources

Section 307(c), 33 U.S.C. 1317(c), of the Act calls for the EPA to promulgate Pretreatment Standards for New Sources (PSNS). Such pretreatment standards must prevent the discharge of any pollutant into a POTW that may interfere with, pass through, or may otherwise be incompatible with the POTW. The EPA promulgates PSNS based on BADCT for new sources. New indirect dischargers have the opportunity to incorporate into their facilities the best available demonstrated technologies. The Agency typically considers the same factors in promulgating PSNS as it considers in promulgating NSPS.

6. Best Professional Judgment

CWA section 301 and its implementing regulation at 40 CFR 125.3(a) indicate that technology-based treatment requirements under section 301(b) of the CWA represent the minimum level of control that must be imposed in an NPDES permit. Where EPA-promulgated effluent guidelines are not applicable to a non-POTW discharge, or where such EPA-promulgated guidelines have been vacated by a court, such treatment requirements are established on a case-by-case basis using the permit writer's BPJ. Case-by-case TBELs are developed pursuant to CWA section 402(a)(1), which authorizes the EPA Administrator to issue a permit that will meet either: all applicable requirements developed under the authority of other sections of the CWA (*e.g.,* technology-based treatment standards, water quality standards, ocean discharge criteria) or, before taking the necessary implementing actions related to those requirements, ''such conditions as the Administrator determines are necessary to carry out the provisions of this Act.'' The regulation at 40 CFR 125.3(c)(2) cites this section of the CWA, stating that technology-based treatment requirements may be imposed in a permit ''on a case-by-case basis under section 402(a)(1) of the Act, to the extent that EPA-promulgated effluent limitations are inapplicable.'' Furthermore, § 125.3(c)(3) indicates, ''[w]here promulgated effluent limitations guidelines only apply to certain aspects of the discharger's operation, or to certain pollutants, other aspects or activities are subject to regulation on a case-by-case basis in order to carry out the provisions of the Act.'' The factors considered by the permit writer are the same as those that the EPA considers in establishing technology-based effluent limitations. *See* 40 CFR 125.3(d)(1) through (3).

C. 2015 Steam Electric Power Generation Point Source Category Rule

1. 2015 Rule Requirements

On November 3, 2015, the EPA promulgated a rule revising the regulations for the Steam Electric Power Generating point source category, 40 CFR part 423. 80 FR 67838, November 3, 2015. The rule set the first Federal limitations on the levels of toxic pollutants (*e.g.,* arsenic) and nutrients (*e.g.,* nitrogen) that can be discharged in the steam electric power generating industry's largest sources of wastewater, based on technology improvements in the steam electric power industry over the preceding three decades. Before the 2015 rule, regulations for the industry were last updated in 1982 and, for the industry's wastestreams with the largest pollutant loadings, contained only limitations on TSS and oil and grease.

Over those 30 years, new technologies for generating electric power and the widespread implementation of air pollution controls had altered existing wastewater streams or created new wastewater streams at many steam electric facilities, particularly coal-fired facilities. Discharges of these wastestreams include arsenic, lead, mercury, selenium, chromium, and cadmium. Once in the environment, many of these toxic pollutants can remain there for years and continue to cause adverse impacts.

The 2015 rule addressed effluent limitations and standards for multiple wastestreams generated by new and existing steam electric facilities: BA transport water, CRL, FGD wastewater, FGMC wastewater, FA transport water, gasification wastewater, and legacy wastewater.[4] The rule required most steam electric facilities to comply with the effluent limitations ''as soon as possible'' after November 1, 2018, and no later than December 31, 2023. NPDES permitting authorities established particular applicability date(s) within that range for each facility (except for indirect dischargers) at the time they reissued the facility's NPDES permit.

The 2015 rule was projected to reduce the amount of metals the CWA defines as toxic pollutants, nutrients, and other pollutants that steam electric facilities are allowed to discharge by 1.4 billion pounds per year and reduce water withdrawal by 57 billion gallons. At the time, the EPA estimated annual compliance costs for the final rule to be $480 million (in 2013 dollars, discounted at 3 percent) and estimated annual benefits associated with the rule to be $451 to $566 million (in 2013 dollars, discounted at 3 percent).

2. Vacatur of Limitations Applicable to CRL and Legacy Wastewater

Seven petitions for review of the 2015 rule were filed in various circuit courts by the electric utility industry, environmental groups, and drinking water utilities. These petitions were consolidated in the U.S. Court of Appeals for the Fifth Circuit, *Southwestern Electric Power Co.* v. *EPA,* Case No. 15–60821 (5th Cir.). On March 24, 2017, the Utility Water Act Group submitted to the EPA an administrative petition for reconsideration of the 2015 rule. On April 5, 2017, the Small Business Administration (SBA) submitted an administrative petition for reconsideration of the 2015 rule.

On August 11, 2017, then EPA Administrator Scott Pruitt announced his decision to conduct a rulemaking to potentially revise the new, more stringent BAT effluent limitations and pretreatment standards for existing sources in the 2015 rule that apply to FGD wastewater and BA transport water. The Fifth Circuit subsequently granted the EPA's request to sever and hold in abeyance petitioners' claims related to those limitations and standards, and those claims are still in abeyance. With respect to the remaining claims related to limitations applicable to legacy wastewater and CRL, the Fifth Circuit issued a decision on April 12, 2019, vacating those limitations as arbitrary and capricious under the Administrative Procedure Act and unlawful under the CWA, respectively. *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d 999. In particular, the Court rejected the EPA's BAT limitations for each wastestream set equal to previously promulgated BPT limitations based on surface impoundments. In the case of legacy wastewater, the Court held that the EPA's record on surface impoundments did not support BAT limitations based on surface impoundments. *Id.* at 1015. In the case of CRL, the Court held that the EPA's setting of BAT limitations equal to BPT limitations was an impermissible conflation of the two standards, which are supposed to be progressively more stringent, and that the EPA's rationale was not authorized by the statutory factors for determining BAT. *Id.* at 1026. After the Court's decision, the EPA announced its plans to address the vacated limitations in a later action after the 2020 rule.

[4] These wastestreams are defined in appendix A to this preamble.

In September 2017 (82 FR 43494), using notice-and-comment procedures, the EPA finalized a rule postponing the earliest compliance dates for the more stringent BAT effluent limitations and PSES for FGD wastewater and BA transport water in the 2015 rule, from November 1, 2018, to November 1, 2020 (''postponement rule''). The EPA also withdrew a prior action it had taken to stay parts of the 2015 rule pursuant to section 705 of the Administrative Procedure Act, 5 U.S.C. 705. The postponement rule received multiple legal challenges, but the courts did not sustain any of them.[5]

D. 2020 Steam Electric Reconsideration Rule and Recent Developments

1. 2020 Rule Requirements

On October 13, 2020, the EPA promulgated the *Steam Electric Reconsideration Rule* (85 FR 64650). The 2020 rule revised requirements for FGD wastewater and BA transport water applicable to existing sources. Specifically, the 2020 rule made four changes to the 2015 rule. First, the rule changed the technology basis for control of FGD wastewater and BA transport water. For FGD wastewater, the technology basis was changed from chemical precipitation plus high-hydraulic-residence-time biological reduction to chemical precipitation plus low-hydraulic-residence-time biological reduction. This change in the technology basis resulted in less stringent selenium limitations but more stringent mercury and nitrogen limitations. For BA transport water, the technology basis was changed from dry-handling or closed-loop systems to high-recycle-rate systems, allowing for a site-specific purge not to exceed 10 percent of the BA transport system's volume. This change in technology resulted in less stringent limitations for all pollutants in BA transport water. Second, the 2020 rule revised the technology basis for the voluntary incentives program (VIP) for FGD wastewater from vapor compression evaporation to chemical precipitation plus membrane filtration. This change in the technology basis resulted in less stringent limitations for most pollutants but added new limitations for bromide and nitrogen. Third, the 2020 rule created three new subcategories for high-flow facilities, LUEGUs, and EGUs permanently ceasing coal combustion by 2028. These subcategories were subject to less stringent limitations: high-flow facilities were subject to FGD wastewater limitations based on chemical precipitation; LUEGUs were subject to FGD wastewater limitations based on chemical precipitation and BA transport water limitations based on surface impoundments and a best management practice (BMP) plan; and EGUs permanently ceasing coal combustion by 2028 were subject to FGD wastewater and BA transport water limitations based on surface impoundments. Finally, the 2020 rule required most steam electric facilities to comply with the revised effluent limitations ''as soon as possible'' after October 13, 2021, and no later than December 31, 2025.[6] NPDES permitting authorities established the particular applicability date(s) of the new limitations within that range for each facility (except for indirect dischargers) at the time they reissued the facility's NPDES permit.

2. Fourth Circuit Court of Appeals Litigation

Two petitions for review of the 2020 rule were timely filed by environmental group petitioners and consolidated in the U.S. Court of Appeals for the Fourth Circuit on November 19, 2020. *Appalachian Voices, et al.* v. *EPA,* No. 20–2187 (4th Cir.). An industry trade group and certain energy companies moved to intervene in the litigation, which the Court granted on December 3, 2020. On April 8, 2022, the Court granted the EPA's motion and placed the case into abeyance pending the completion of the current rulemaking.

3. Executive Order 13990 and Announcement of Supplemental Rule

On January 20, 2021, President Biden issued Executive Order 13990: *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis.* 86 FR 7037. Executive Order 13990 directed Federal agencies to immediately review and, as appropriate and consistent with applicable law, take action to address the promulgation of Federal regulations and other actions during the previous four years that conflict with the national objectives of protecting public health and the environment.

On July 26, 2021, the EPA announced a new rulemaking to strengthen certain wastewater pollution discharge limitations for coal-fired power plants that use steam to generate electricity (86 FR 41801, August 3, 2021). The EPA later clarified that, as part of its new rulemaking, it would be reconsidering all aspects of the 2020 rule. The EPA undertook an evidence-based, science-based review of the 2020 rule under Executive Order 13990, finding that there are opportunities to strengthen certain wastewater pollution discharge limitations. For example, the EPA discussed how treatment systems using membranes have advanced since the 2020 rule's promulgation and continue to rapidly advance as an effective option for treating a wide variety of industrial pollution, including pollution from steam electric power plants. In the announcement, the EPA also clarified that, until a new rule is promulgated, part 423 will continue to be implemented and enforced to achieve needed pollutant reductions.[7]

4. Preliminary Effluent Guidelines Plan 15

In September 2021, the EPA issued *Preliminary Effluent Guidelines Program Plan 15*.[8] This document discussed the annual review of ELGs, rulemakings for new and existing industrial point source categories, and any new or existing sources receiving further analyses. Here, in the context of the EPA's ongoing steam electric ELG rulemaking, EPA noted relevant wastestreams including pointing out that the 2015 rule limitations for CRL and legacy wastewater had been vacated and remanded to the Agency. For further discussion of the vacatur and remand of the 2015 limitations applicable to CRL and legacy wastewater, see section IV.D of this preamble.

E. Other Ongoing EPA Rules Impacting the Steam Electric Sector

The EPA has recently proposed or finalized several other rules to protect the nation's air, land, and water from pollution resulting from coal-fired power plants. The EPA has primarily considered these other rules to support this final rulemaking in two ways. First, when appropriate, the EPA has included the impacts of final rules in the baseline of its analyses. Second, the EPA has designed this final rule to harmonize compliance dates, subcategories, and other aspects of these rules to the extent possible and appropriate under different statutory schemes. The following sections summarize the solid waste and

[5] *See Center for Biological Diversity* v. *EPA,* No. 18–cv–00050 (D. Ariz. filed January 20, 2018); *see also Clean Water Action.* v. *EPA,* No. 18–60079 (5th Cir.). On October 29, 2018, the District of Arizona case was dismissed upon the EPA's motion to dismiss for lack of jurisdiction, and on August 28, 2019, the Fifth Circuit denied the petition for review of the postponement rule.

[6] The 2015 rule's VIP compliance date was revised to December 31, 2028, in the 2020 rule.

[7] This includes both the 2020 rule and portions of the 2015 rule which were not revised or vacated.

[8] Available online at: *www.epa.gov/system/files/documents/2021-09/ow-prelim-elg-plan-15_508.pdf.*

air rules that are most directly relevant to the electric power sector.

1. Coal Combustion Residuals Disposal Rule

On April 17, 2015, the EPA promulgated the Disposal of Coal Combustion Residuals from Electric Utilities final rule (2015 CCR rule) (80 FR 21302). This rule finalized national regulations to provide a comprehensive set of requirements for the safe disposal of CCR, commonly referred to as coal ash, from steam electric power plants. The final 2015 CCR rule was the culmination of extensive study on the effects of coal ash on the environment and public health. The rule established technical requirements for CCR landfills and surface impoundments under subtitle D of the Resource Conservation and Recovery Act (RCRA), the Nation's primary law for regulating solid waste.

These regulations established requirements for the management and disposal of coal ash, including requirements designed to prevent leaking of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. The 2015 CCR rule also set recordkeeping and reporting requirements, as well as requirements for each plant to establish and post specific information to a publicly accessible website. The rule also established requirements to distinguish the beneficial use of CCR from disposal.

As a result of the D.C. Circuit Court decisions in *Utility Solid Waste Activities Group* v. *EPA,* 901 F.3d 414 (D.C. Cir. 2018) (''*USWAG* decision'' or ''*USWAG*''), and *Waterkeeper Alliance Inc. et al.* v. *EPA,* No. 18–1289 (D.C. Cir. filed March 13, 2019), the Administrator signed two rules: *A Holistic Approach to Closure Part A: Deadline to Initiate Closure and Enhancing Public Access to Information* (CCR Part A rule) (85 FR 53516, August 28, 2020) on July 29, 2020, and *A Holistic Approach to Closure Part B: Alternate Liner Demonstration* (CCR Part B rule) (85 FR 72506, December 14, 2020) on October 15, 2020. The EPA finalized five amendments to the 2015 CCR rule which are relevant to the management of the wastewaters covered by this ELG because these wastewaters have historically been co-managed with CCR in the same surface impoundments. First, the CCR Part A rule established a new deadline of April 11, 2021, for all unlined surface impoundments in which CCR are managed (''CCR surface impoundments''), as well as CCR surface impoundments that failed the location restriction for placement above the uppermost aquifer, to stop receiving waste and begin closure or retrofitting. The EPA established this date after evaluating the steps that owners and operators need to take for CCR surface impoundments to stop receiving waste and begin closure, and the timeframes needed for implementation. (This did not affect the ability of plants to install new, composite-lined CCR surface impoundments.) Second, the Part A rule established procedures for plants to obtain approval from the EPA for additional time to develop alternative disposal capacity to manage their wastestreams (both CCR and non-CCR) before they must stop receiving waste and begin closing their CCR surface impoundments. Third, the Part A rule changed the classification of compacted-soil-lined and clay-lined surface impoundments from lined to unlined. Fourth, the Part B rule finalized procedures potentially allowing a limited number of facilities to demonstrate to the EPA that, based on groundwater data and the design of a particular surface impoundment, the unit ensures there is no reasonable probability of adverse effects to human health and the environment. Should the EPA approve such a submission, these CCR surface impoundments would be allowed to continue to operate.

As explained in the 2015 and 2020 ELG rules, the ELGs and CCR rules may affect the same EGU or activity at a plant. Therefore, when the EPA finalized the ELG and CCR rules in 2015, and revisions to both rules in 2020, the Agency coordinated the ELG and CCR rules to minimize the complexity of implementing engineering, financial, and permitting activities. Likewise, the EPA considered the interaction of the two rules during the development of this final rule. The EPA's analytic baseline includes the final requirements of these rules using the most recent data provided under the CCR rule reporting and recordkeeping requirements. This is further described in Supplemental TDD, section 3. For more information on the CCR Part A and Part B rules, including information about their ongoing implementation, visit *www.epa.gov/coalash/coal-ash-rule.*

Concurrently with the final ELG, in a separate rulemaking, the EPA is also finalizing regulatory requirements for inactive CCR surface impoundments at inactive utilities (''legacy CCR surface impoundment'' or ''legacy impoundment'') (FR 2024–09157 (EPA–HQ–OLEM–2020–0107; FRL–7814–04–OLEM)). This action is being taken in response to the August 21, 2018, opinion by the U.S. Court of Appeals for the District of Columbia Circuit in the *USWAG* decision that vacated and remanded the provision exempting legacy impoundments from the CCR regulations. This action includes adding a definition for legacy CCR surface impoundments and other terms relevant to this rulemaking. It also requires that legacy CCR surface impoundments comply with certain existing CCR regulations with tailored compliance deadlines.

The EPA is also establishing requirements to address the risks from currently exempt solid waste management that involves the direct placement of CCR on the land. The EPA is extending a subset of the existing requirements in 40 CFR part 257, subpart D, to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR rule, inactive CCR landfills, and other areas where CCR is managed directly on the land. In this action, the EPA refers to these as CCR management units, or CCRMU. This rule will apply to all existing CCR facilities and all inactive facilities with legacy CCR surface impoundments subject to this final rule.

Finally, the EPA is making a number of technical corrections to the existing regulations, such as correcting certain citations and harmonizing definitions. For further information on the CCR regulations, including information about the CCR Part A and Part B rules' ongoing implementation, visit *www.epa.gov/coalash/coal-ash-rule.*

2. Air Pollution Rules and Implementation

The EPA is taking several actions to regulate a variety of conventional, hazardous, and greenhouse gas (GHG) air pollutants, including actions to regulate the same steam electric power plants subject to part 423. In light of these ongoing actions, the EPA has worked to consider appropriate flexibilities in this ELG rule to provide certainty to the regulated community while ensuring the statutory objectives of each program are achieved. Furthermore, to the extent that these actions have been published before this rule's signature and are already impacting steam electric power plant operations, the EPA has accounted for these changed operations in its Integrated Planning Model (IPM) modeling discussed in section VIII of this preamble.

a. The Revised Cross State Air Pollution Rule Update and the Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards

On June 5, 2023, the EPA promulgated its final Good Neighbor Plan, which secures significant reductions in ozone-forming emissions of nitrogen oxides (NO_X) from power plants and industrial facilities. 88 FR 36654. The Good Neighbor Plan ensures that 23 states meet the Clean Air Act's (CAA's) ''Good Neighbor'' requirements by reducing pollution that significantly contributes to problems attaining and maintaining EPA's health-based air quality standard for ground-level ozone (or ''smog''), known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS), in downwind states. Further information on this action is available on the EPA's website.[9]

As of September 21, 2023, the Good Neighbor Plan's ''Group 3'' ozone-season NO_X control program for power plants is being implemented in: Illinois, Indiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and Wisconsin. Pursuant to court orders staying the Agency's State Implementation Plan disapproval action in the following States, the EPA is not currently implementing the Good Neighbor Plan ''Group 3'' ozone-season NO_X control program for power plants in: Alabama, Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and West Virginia.[10]

On January 16, 2024, the EPA signed a proposal to partially approve and partially disapprove State Implementation Plan submittals addressing interstate transport for the 2015 ozone NAAQS from Arizona, Iowa, Kansas, New Mexico, and Tennessee and proposed to include these States in the Good Neighbor Plan beginning in 2025 (89 FR 12666, February 16, 2024).

On April 30, 2021, the EPA published the final Revised Cross-State Air Pollution Rule (CSAPR) Update (86 FR 23054), which resolved 21 states' good neighbor obligations for the 2008 ozone NAAQS, following the remand of the 2016 CSAPR Update (81 FR 74504, October 26, 2016) in *Wisconsin* v. *EPA,* 938 F.3d 308 (D.C. Cir. 2019). Together, these two rules establish the Group 2 and Group 3 market-based emissions trading programs for 22 states in the eastern United States for emissions of NO_X from fossil fuel-fired EGUs during the summer ozone season.

b. Clean Air Act section 111 Rule

Concurrently with the final ELG, the EPA is finalizing the repeal of the Affordable Clean Energy Rule, establishing Best System of Emissions Reduction (BSER) determinations and emission guidelines for existing fossil fuel-fired EGUs, and establishing BSER determinations and accompanying standards of performance for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbines and modified fossil fuel-fired EGUs. Specifically, for coal-fired EGUs, the EPA is establishing final standards based on carbon capture and storage/sequestration with 90 percent capture with a compliance date of January 1, 2032 (FR 2024–09233 (EPA–HQ–OAR–2023–0072; FRL–8536–01–OAR)). For coal-fired EGUs retiring by January 1, 2039, the EPA is establishing final standards based on 40 percent natural gas co-firing with a compliance date of January 1, 2030.

While four subcategories for coal-fired EGUs were proposed, the EPA is finalizing just the two subcategories for coal-fired EGUs as described in the preceding paragraph. Consistent with 40 CFR 60.24a(e) and the Agency's explanation in the proposal, states have the ability to consider, *inter alia,* a particular source's remaining useful life when applying a standard of performance to that source.[11]

In addition, the EPA is creating an option for states to provide for a compliance date extension for existing sources of up to one year under certain circumstances for sources that are installing control technologies to comply with their standards of performance. States may also provide, by inclusion in their state plans, a reliability assurance mechanism of up to one year that under limited circumstances would allow existing EGUs that had planned to cease operating by a certain date to temporarily remain available to support reliability. Any extensions exceeding 1-year must be addressed through a state plan revision. Further information about the CAA section 111 rule is available online at *https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.*

c. Mercury and Air Toxics Standards Rule

On March 6, 2023 (88 FR 13956), the EPA published a final rule which reaffirmed that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost. This action revoked a 2020 finding that it was not appropriate and necessary to regulate coal- and oil-fired power plants under CAA section 112, which covers toxic air pollutants. The EPA reviewed the 2020 finding and considered updated information on both the public health burden associated with HAP emissions from coal- and oil-fired power plants, as well as the costs associated with reducing those emissions under the Mercury and Air Toxics Standards (MATS). After weighing the public risks these emissions pose to all Americans (and particularly exposed and sensitive populations) against the costs of reducing this harmful pollution, the EPA concluded that it remains appropriate and necessary to regulate these emissions. This action ensures that coal- and oil-fired power plants continue to control emissions of hazardous air pollution and that the Agency properly interprets the CAA to protect the public from hazardous air emissions.

Concurrently with the final ELG, the EPA is finalizing an update to the National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly known as the Mercury and Air Toxics Standards (MATS) for power plants, to reflect recent developments in control technologies and the performance of these plants (FR 2024–0918 (EPA–HQ–OAR–2018–0794; FRL–6716.3–02–OAR)). This final rule includes an important set of improvements and updates to MATS and also fulfills the EPA's responsibility under the Clean Air Act to periodically re-evaluate its standards in light of advancements in pollution control technologies to determine whether revisions are necessary. The improvements consist of:

- Further limiting the emission of non-mercury HAP metals from existing coal-fired power plants by significantly reducing the emission standard for filterable particulate matter (fPM), which is designed to control non-mercury HAP metals. The EPA is finalizing a two-thirds reduction in the fPM standard; [12]

[9] *See https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.*

[10] Further information on EPA's response to the stay orders can be found online at: *https://www.epa.gov/Cross-State-Air-Pollution/epa-response-judicial-stay-orders.*

[11] See 88 FR 33240 (May 23, 2023) (invoking RULOF based on a particular coal-fired EGU's remaining useful life ''is not prohibited under these emission guidelines'').

[12] Also, the EPA is finalizing the removal of the low-emitting EGU provisions for fPM and non-mercury HAP metals.

- Tightening the emission limit for mercury for existing lignite-fired power plants by 70 percent; [13]
- Strengthening emissions monitoring and compliance by requiring coal-and oil-fired EGUs to comply with the fPM standard using PM continuous emission monitoring systems (CEMS); [14]
- Revising the startup requirements in MATS to assure better emissions performance during startup.

Additional information on the final MATS is available on the EPA's website.[15]

d. National Ambient Air Quality Standards Rules for Particulate Matter

On February 7, 2024, the EPA Administrator signed a final rule strengthening the National Ambient Air Quality Standards for Particulate Matter (PM NAAQS) to protect millions of Americans from harmful and costly health impacts, such as heart attacks and premature death (89 FR 16202, March 6, 2024). Particle or soot pollution is one of the most dangerous forms of air pollution, and an extensive body of science links it to a range of serious and in some cases deadly illnesses. The EPA set the level of the primary (health-based) annual particulate matter ($PM_{2.5}$) standard at 9.0 micrograms per cubic meter to provide increased public health protection, consistent with the available health science. The EPA did not change the current primary and secondary (welfare-based) 24-hour $PM_{2.5}$ standards, the secondary annual $PM_{2.5}$ standard, and the primary and secondary PM_{10} standards. The EPA also revised the Air Quality Index to improve public communications about the risks from $PM_{2.5}$ exposures and made changes to the monitoring network to enhance protection of air quality in communities overburdened by air pollution. More information about this action is available on the EPA's website.[16]

V. Steam Electric Power Generating Industry Description

A. General Description of Industry

For each previous regulatory action—the 2013 proposed rule (78 FR 34432, June 7, 2013), the 2015 final rule, the 2019 proposed rule (84 FR 64620, November 22, 2019), the 2020 final rule, and the 2023 proposed rule—the EPA provided general descriptions of the steam electric power generating industry. The Agency has continued to collect information and update this industry profile. The previous descriptions reflected the known information about the universe of steam electric power plants and incorporated final environmental regulations applicable at that time. For this rule, as described in the Supplemental TDD, section 3, the EPA has revised its description of the steam electric power generating industry (and its supporting analyses) to incorporate major changes such as additional retirements, fuel conversions, ash handling conversions, wastewater treatment updates, and updated information on capacity utilization.[17] The analyses supporting this rule use an updated baseline that incorporates these changes in the industry and include the 2015 and 2020 rules' limitations for FGD wastewater, BA transport water, CRL, and legacy wastewater. The analyses then compare the effect of the new rule's requirements to this baseline.

As described in the Regulatory Impact Analysis, of the 858 steam electric power plants in the country identified by the EPA, only those coal-fired power plants that discharge FGD wastewater, BA transport water, CRL, legacy wastewater and/or unmanaged CRL may incur compliance costs under this rule. The EPA estimates that 141 to 170 such plants may incur compliance costs under this rule, depending on the scenario used to model the occurrence of unmanaged CRL costs. See section VII.C.5 of this preamble for more information regarding subcategory for discharges of unmanaged CRL. See the EPA's memorandum, *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule* (DCN SE11618), for more information about plant retirements, fuel conversions, ash handling conversions, wastewater treatment updates, and updated information on capacity utilization.

B. Current Market Conditions and Drivers in the Electricity Generation Sector

1. Inflation Reduction Act Implementation

On August 16, 2022, President Biden signed into law the Inflation Reduction Act (IRA). The IRA marks the most significant action Congress has taken on clean energy and climate change in the nation's history. The IRA provides tax credits, financing programs, and other incentives, some of which are administered by the EPA, that will accelerate the transition to forms of energy that produce little or no GHG emissions and other water and air pollutants. As such, it includes many provisions that will affect the steam electric power generating industry, causing both direct effects through changes in the production of electricity and indirect effects on electricity demand and changes to fuel markets.

In September 2023, the EPA published a report on the effect of the IRA on the electricity sector and on the economy in general.[18] The report found that the IRA would lead to emission reductions from the electric power sector of 49 to 83 percent below 2005 levels in 2030. The associated shifts from fossil fuel generation would also lead to reductions in water and air pollution from the sector. The study also found that the IRA would lower economy-wide CO_2 emissions, including emissions from electricity generation and use, by 35 to 43 percent below 2005 levels in 2030. Across the end-use sectors, the study found that buildings exhibit the greatest reductions from 2005 levels of direct plus indirect CO_2 emissions from electricity, followed by industry and transportation. Though it focuses on changes in climate-forcing emissions (in part attributable to the models it uses), the study also implies important changes in the emissions of other pollutants throughout the economy. The EPA used IPM to evaluate the impacts of the final ELG relative to a baseline that reflects impacts from other relevant policies and environmental regulations that affect the power sector, including the IRA and other on-the-books Federal and state rules (*see* section VIII.C.2 of this preamble for more information).

[13] This level aligns with the mercury standard that other coal-fired power plants have been achieving under the current MATS.

[14] PM CEMS provide regulators, the public, and facility owners or operators with cost-effective, accurate, and continuous emission measurements. This real-time, quality-assured feedback can lead to improved control device and power plant operation, which will reduce air pollutant emissions and exposure for local communities.

[15] *See https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards.*

[16] *See https://www.epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm.*

[17] The data presented in the general description continue to reflect some conditions existing in 2009.The 2010 steam electric industry survey remains the EPA's best available source of information for characterizing operations across the industry in cases where the EPA has not received newer information.

[18] U.S. EPA (Environmental Protection Agency). 2023. *Electricity Sector Emissions Impacts of the Inflation Reduction Act: Assessment of Projected CO_2 Emission Reductions from Changes in Electricity Generation and Use.* U EPA 430–R–23–004. Available online at: *https://www.epa.gov/inflation-reduction-act/electric-sector-emissions-impacts-inflation-reduction-act.*

2. Recent Developments in Ensuring Electric Reliability and Resource Adequacy

The nature and components of the bulk power sector have been evolving away from older and less efficient legacy fossil generation (mostly coal-fired power plants) towards more decentralized, renewable assets and flexible gas-fired generation. Stakeholders have raised concerns that centralized, dispatchable power plants are coming offline faster than new generation can replace the reliability attributes associated with them. However, a combination of technology innovation, revised market signals from the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), and reforms recently completed and underway by Federal Energy Regulatory Commission (FERC) are collectively poised to address current reliability challenges associated with the transition along with expected higher load growth and the increasing frequency of extreme weather events. EPA has continued to learn and engage on reliability issues, particularly as part of the Agency's implementation of the *Joint Memorandum on Interagency Communication and Consultation on Electric Reliability*.[19] As part of this process, EPA has engaged in regular meetings with Department of Energy (DOE), North American Electric Reliability Corporation (NERC), FERC, and the various ISOs/RTOs.

FERC, NERC, RTOs, and ISOs are already taking steps to ensure reliability during this period of asset evolution. Among FERC's actions to help address reliability is Order 2023, or ''Improvements to Generator Interconnection Procedures,'' which will help expedite interconnections for new assets waiting to connect to the grid. This is a very important development to ensure future resource adequacy because interconnection wait times for new energy assets entering energy markets have increased, which is stifling the ability of replacement generation to connect to the grid. FERC's final action on extreme cold weather preparedness will support the new peak demand hours, which have migrated to winter months. New reliability standards issued for inverter-based resources ''will help ensure reliability of the grid by accommodating the rapid integration of new power generation technologies, known as inverter-based resources (IBRs), that include solar photovoltaic, wind, fuel cell and battery storage resources. . . .'' [20] FERC has also undertaken various transmission-related efforts, from inter-regional transmission capacity efforts to reconductoring and dynamic line rating, that would help bolster reliability by increasing the transmission capacity of existing lines and creating incentives for new, inter-regional transmission. Increasing transmission capacity can enhance reliability by increasing the amount of generation that can access the grid to help meet demand.

Furthermore, there are new technologies coming online that can also help provide reliability attributes. The deployment of many of these technologies has been accelerating due to the incentives in the IRA. The rapid increase in energy storage deployment across the nation is an important part of future grid reliability, particularly as the duration of storage assets expands. Examples of existing and emerging storage resources include various types of fuel cells, batteries, pumped hydro-electric reservoirs, and underground hydrogen caverns. Energy storage can help buttress reliability by storing renewable energy for dispatch when demand is high. Improved management of demand response assets, better designed electricity tariff structures, aggregation of distributed resources like roof-top solar panels, and integration of behind-the-meter battery storage can further support balancing peak demand on power grids. For example, programs to manage demand, which have shown value well before the recent energy transition, incentivize customers to shift their demand during periods when there is ample supply, which can help reduce instances when supply is tight.

Despite these concerns, there are also existing procedures in place to ensure electricity system reliability and resource adequacy over both the short and long-term. For example, regional planning organizations typically have incentive or planning procedures to ensure that there is sufficient capacity to meet future demand such as day-ahead reserve and capacity markets and seasonal reserve margins. Furthermore, the EPA understands that before a unit implements a retirement decision, the unit's owner will follow the processes put in place by the relevant RTO, balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place.

C. Control and Treatment Technologies

In general, control and treatment technologies for some wastestreams have continued to advance since the 2015 and 2020 rules. Often, these advancements provide plants with additional approaches for complying with any effluent limitations. In some cases, these advancements have also decreased the associated costs of compliance. For this rule, the EPA incorporated updated information and evaluated several technologies available to control and treat FGD wastewater, BA transport water, CRL, and legacy wastewater generated by the steam electric power generating industry. See section VIII of this preamble for details on updated cost information.

1. FGD Wastewater

FGD scrubber systems are used to remove sulfur dioxide from flue gas so it is not emitted into the air. Dry FGD systems use water in their operation but generally do not discharge wastewater because it evaporates during operation. Wet FGD systems do produce a wastewater stream.

Steam electric power plants discharging FGD wastewater currently employ a variety of wastewater treatment technologies and operating/management practices to reduce the pollutants associated with FGD wastewater discharges. The EPA identified the following types of treatment and handling practices for FGD wastewater:

- Chemical precipitation. Chemicals are added as part of the treatment system to help remove suspended solids and dissolved solids, particularly metals. The precipitated solids are then removed from the solution by coagulation/flocculation followed by clarification and/or filtration. The 2015 and 2020 rules focused on a specific design that employs hydroxide precipitation, sulfide precipitation (organosulfide), and iron coprecipitation to remove suspended solids and convert soluble metal ions to insoluble metal hydroxides or sulfides. Chemical precipitation was part of the BAT technology basis for the effluent limitations in the 2015 and 2020 rules.
- High-hydraulic-residence-time biological reduction (HRTR). The EPA

[19] Available online at: *https://www.epa.gov/power-sector/electric-reliability-mou.*

[20] For further information about FERC actions to address IBRs, *see https://www.ferc.gov/news-events/news/ferc-moves-protect-grid-transition-clean-energy-resources.*

identified three types of biological treatment systems used to treat FGD wastewater: anoxic/anaerobic fixed-film bioreactors (which target removals of nitrogen compounds and selenium), anoxic/anaerobic suspended growth systems (which target removals of selenium and other metals), and aerobic/anaerobic sequencing batch reactors (which target removals of organics and nutrients). An anoxic/anaerobic fixed-film bioreactor designed to remove selenium and nitrogen compounds using high hydraulic residence times of approximately 10 to 16 hours was part of the BAT technology basis for the effluent limitations in the 2015 rule.

• Low-hydraulic-residence-time biological reduction (LRTR). LRTR is a biological treatment system that targets removal of selenium and nitrate/nitrite using fixed-film bioreactors in smaller, more compact reaction vessels. This system differs from the HRTR biological treatment system evaluated in the 2015 rule, in that the LRTR system is designed to operate with a shorter residence time (approximately one to four hours, compared to a residence time of 10 to 16 hours for HRTR) while still achieving significant removal of selenium and nitrate/nitrite. LRTR was part of the BAT technology basis for the effluent limitations in the 2020 rule.

• Membrane filtration. A membrane filtration system (*e.g.,* microfiltration, ultrafiltration, nanofiltration, forward osmosis, electrodialysis reversal, or reverse osmosis (RO)) is designed specifically for high-TDS and high-TSS wastestreams. These systems are designed to minimize fouling and scaling associated with industrial wastewater. These systems typically use pretreatment for potential scaling agents (*e.g.,* calcium, magnesium, sulfates) combined with one or more type of membrane technology to remove a broad array of particulate and dissolved pollutants from FGD wastewater. The membrane filtration units may also employ advanced techniques, such as vibration or creation of vortexes to mitigate fouling or scaling of the membrane surfaces. Membrane filtration can achieve zero discharge by recirculating permeate from an RO system back into plant operations.

• Spray evaporation. Spray evaporation technologies, which include spray dry evaporators (SDEs) and other similar proprietary variations, evaporate water by spraying fine misted wastewater into hot gases. The hot gases allow the water to evaporate before contacting the walls of an evaporation vessel, treating wastewater across a range of water quality characteristics such as TDS, TSS, or scale forming potential. Spray evaporation technologies use a less complex treatment configuration than brine concentrator and crystallizer systems (see the description of thermal evaporation systems) to evaporate water using a heat source, such as a slipstream of hot flue gas or an external natural gas burner. Spray evaporation technologies can be used in combination with other volume reduction technologies, such as membranes, to maximize the efficiency of each process. Concentrate from an RO system can then be processed through the spray evaporation technology to achieve zero discharge by recirculating permeate from the RO system back into plant operations.

• Thermal evaporation. Thermal evaporation systems use a falling-film evaporator (or brine concentrator), following a softening pretreatment step, to produce a concentrated wastewater stream and a distillate stream to reduce wastewater volume by 80 to 90 percent and reduce the discharge of pollutants. The concentrated wastewater is usually further processed in a crystallizer that produces a solid residue for landfill disposal and additional distillate that can be reused within the plant or discharged. These systems are designed to remove the broad spectrum of pollutants present in FGD wastewater to very low effluent concentrations.

• Some plants operate their wet FGD systems using approaches that eliminate the discharge of FGD wastewater. These plants use a variety of operating and management practices to achieve this, including the following:

—Complete recycle. The FGD wastestream is allowed to recirculate. Particulates (*e.g.,* precipitates and other solids) are removed and landfilled. Water is supplemented when needed to replace water that evaporated or was removed with landfilled solids. This process does not produce a saleable product (*e.g.,* wallboard grade gypsum) but it does not need a wastewater purge stream to maintain low levels of chlorides.

—Evaporation impoundments. Some plants located in warm, dry climates use surface impoundments as holding basins where the FGD wastewater is retained until it evaporates. The evaporation rate from these impoundments is greater than the flow rate of the FGD wastewater and amount of precipitation entering the impoundments; therefore, there is no discharge to surface water.[21] These impoundments must be large enough to accommodate extreme precipitation events to prevent overtopping and runoff.

—FA conditioning. Many plants that operate dry FA handling systems use the water from their FGD system in the FA handling system to suppress dust or improve handling and/or compaction characteristics in an on-site landfill.

—Combination of wet and dry FGD systems. The dry FGD process involves atomizing and injecting wet lime slurry, which ranges from approximately 18 to 25 percent solids, into a spray dryer. The water contained in the slurry evaporates from the heat of the flue gas within the system, leaving a dry residue that is removed from the flue gas using a fabric filter (*i.e.,* baghouse) or electrostatic precipitator.

—Underground injection. These systems dispose of wastes by injecting them into a permitted underground injection well as an alternative to discharging wastewater to surface waters.

The EPA also collected information on other FGD wastewater treatment technologies, including direct contact thermal evaporators and ion exchange. These treatment technologies have been evaluated, in full- or pilot-scale, or are being developed to treat FGD wastewater. More information on these technologies is available in section 4.1 of the Supplemental TDD.

2. BA Transport Water

BA (bottom ash) consists of heavier ash particles that are not entrained in the flue gas and fall to the bottom of the furnace. In most furnaces, the hot BA is quenched in a water-filled hopper.[22] Some plants use water to transport (sluice) the BA from the hopper to an impoundment or dewatering bins. The water used to transport the BA to the impoundment or dewatering bins is usually discharged to surface water as overflow from the systems after the BA has settled to the bottom. The industry also uses the following BA handling systems that generate BA transport water:

• Remote mechanical drag system (MDS). These systems transport BA to a remote MDS using the same processes as wet-sluicing systems. A drag chain conveyor pulls the BA out of the water bath on an incline to dewater the BA. The system can be operated either as a

[21] Such impoundments must be lined based on the requirements in the CCR rule. This lining would significantly reduce the potential for a discharge through groundwater that would be the functional equivalent of a direct discharge to a WOTUS.

[22] Consistent with the 2015 and 2020 rule, EGU slag is considered BA.

closed-loop system (part of the technology basis for the 2015 rule) or a high-recycle-rate system (technology basis for the 2020 rule).[23]

- Mobile MDS. This technology is a smaller, mobile version of a remote MDS with an additional clarification system. It is not intended to be a permanent installation, which allows facilities to reduce capital costs. Once in place, the system works like a remote MDS—the incoming water is clarified and primary separation occurs. The clarified water is taken from the mechanical drag system to a mobile clarifier and polished to a level suitable for recirculation. The mobile clarifier thickens the collected solids, which are then sent back to the mechanical drag system portion and mixed with coarse BA. This mixture is sent up an incline, dewatered, and disposed of.
- Dense slurry system. These systems use a dry vacuum or pressure system to convey the BA to a silo (as described below for the ''dry vacuum or pressure system''), but instead of using trucks to transport the BA to a landfill, the plant mixes the BA with a lower percentage of water compared to a wet-sluicing system and pumps the mixture to the landfill.

As part of the 2020 rule and this rule, the EPA identified the following BA handling systems that do not, by definition or practice, generate BA transport water.

- MDS. These systems are located directly underneath the EGU. The BA is collected in a water quench bath. A drag chain conveyor pulls the BA out of the water bath along an incline to dewater the BA.
- Dry mechanical conveyor. These systems are located directly underneath the EGU. The system uses ambient air to cool the BA in the boiler and then transports the ash out from under the EGU using a conveyor. There is no water used in this process.
- Dry vacuum or pressure system. These systems transport BA from the EGU to a dry hopper without using any water. Air is percolated through the ash to cool it and combust unburned carbon. Cooled ash then drops to a crusher and is conveyed via vacuum or pressure to an intermediate storage destination.
- Vibratory belt system. These systems deposit BA on a vibratory conveyor trough, where the ash is air-cooled and ultimately moved through the conveyor deck to an intermediate storage destination without using any water.
- Submerged grind conveyor. These systems are located directly underneath the EGU and are designed to reuse slag tanks, ash gates, clinker grinders, and transfer enclosures from the existing wet sluicing systems. The system collects BA from the discharge of each clinker grinder. A series of submerged drag chain conveyors transport and dewater the BA.

More information on these technologies is available in section 4.2 of the Supplemental TDD.

3. CRL

In promulgating the 2015 rule, the EPA determined that CRL from landfills and impoundments includes similar types of constituents as FGD wastewater, albeit at potentially lower concentrations and smaller volumes. Based on this characterization of the wastewater and knowledge of treatment technologies, the EPA determined that certain treatment technologies identified for FGD wastewater could also be used to treat CRL. These technologies, described in section V.C.1 of this preamble, include chemical precipitation, biological treatment (including LRTR), membrane filtration, spray evaporation, or other thermal treatment options. The EPA also identified other management and reuse strategies from responses to the 2010 *Questionnaire for the Steam Electric Power Generating Effluent Guidelines,* or steam electric survey, which included using CRL from either an impoundment or landfill for moisture conditioning FA, dust control, or truck wash. The EPA also identified plants that collect CRL from impoundments and recycle it directly back to the impoundment.

4. Legacy Wastewater

Legacy wastewater can be composed of FGD wastewater, BA transport water, FA transport water, CRL, gasification wastewater and/or FGMC wastewater generated before the ''as soon as possible'' date that more stringent effluent limitations from the 2015 or 2020 rules would apply. Discharges of legacy wastewater may occur through an intermediary source (*e.g.,* a tank or surface impoundment) or directly into a surface waterbody, with the vast majority of legacy wastewater currently contained in surface impoundments resulting from treating the wastestreams listed above to the previously established BPT limitations. The record indicates that the following technologies can be applied to treat this type of legacy wastewater: chemical precipitation, biological treatment (including LRTR), membrane filtration, spray evaporation, and other thermal treatment options. These technologies are described in section V.C.1 of this preamble. Another option, which may be used in combination with other systems such as chemical and physical treatment, is zero valent iron (ZVI).

- ZVI. This technology can be used to target specific inorganics, including selenium, arsenic, nitrate, and mercury in this type of legacy wastewater. The technology entails mixing influent wastewater with ZVI (iron in its elemental form), which reacts with oxyanions, metal cations, and some organic molecules in wastewater. ZVI causes a reduction reaction in these pollutants, after which the pollutants are immobilized through surface adsorption onto iron oxide coated on the ZVI or generated from oxidation of elemental iron. The coated, or spent, ZVI is separated from the wastewater with a clarifier. The quantity of ZVI required and number of reaction vessels can vary based on the composition and amount of wastewater being treated.

The EPA recognizes that the characterization of legacy wastewater differs within the layers of a CCR impoundment as it is dewatered and prepared for closure. Therefore, treatment requirements may change as closure continues. Wastewater characteristics may also differ across CCR impoundments due to the different types of fuels burned at the plant, duration of pond operation, and ash type. Each of the treatment technologies identified for legacy wastewater above is applicable to all legacy wastewaters; treatment may require a combination of those technologies (*e.g.,* chemical precipitation and membrane filtration).

In addition, solids dewatering is necessary to dredge CCR materials from the impoundment. Mobile dewatering systems are typically self-contained units on a trailer, allowing for the entire system to be easily moved on-site and off-site. Legacy wastewater from a holding area (*e.g.,* pit, pond, collection tank) is pumped through a filter press to generate a filter cake and water stream. A shaker screen can be added to the treatment train to remove larger particles prior to the filter press. Furthermore, the filter press can be equipped with automated plate shifters to allow solids to drop from the end of the trailer directly into a loader or truck. The resulting wastestream may be further treated to meet any discharge requirements.

[23] In some cases, additional treatment may be necessary to maintain a closed-loop system. This additional treatment could include polymer addition to enhance removal of suspended solids or membrane filtration of a slipstream to remove dissolved solids.

VI. Data Collection Since the 2020 Rule

A. Information from the Electric Utility Industry

1. Data Requests and Responses

In January 2022, the EPA requested the following pollution treatment system performance and cost information for coal-fired power plants from three steam electric power companies:

- FGD wastewater installations of the following technologies: thermal technology; membrane filtration technology; paste, solidification, or encapsulation of FGD wastewater brine; electrodialysis; and electrocoagulation.
- Overflow from an MDS, a compact submerged conveyor, or remote MDS installations, including purge rate and management from remote MDS systems, as well as any pollutant concentration data to characterize the overflow or purge.
- CRL treatment from on-site or off-site testing (full-, pilot-, or laboratory-scale).
- On-site or off-site testing (full-, pilot-, or laboratory-scale) and/or implementation of treatment technologies associated with surface impoundment dewatering treatment.
- Costs associated with these technologies.

In addition, after meeting with four additional power companies, the EPA sent each company a voluntary request inviting them to provide the same data described above.

In July 2023, the EPA requested any full-, pilot-, or laboratory-scale data associated with on-site or off-site testing or implementation of a recently commissioned spray dryer evaporator for FGD wastewater and legacy wastewater at a coal-fired power plant from Minnesota Power. The EPA also requested information on pretreatment or disposal systems necessary for continued spray dryer evaporator operations and any corresponding documentation (*e.g.,* wastestreams generated, process flow diagram).

2. Meetings With Individual Utilities

To gather information to support this supplemental rule, the EPA met with representatives from four utilities. Two of these utilities reached out to the EPA after the announcement of the supplemental rulemaking. The EPA contacted the remaining utilities due to their known or potential consideration of membrane filtration. At these meetings, the EPA discussed the operation of the utility's coal-fired EGUs and the treatment and management of BA transport water, FGD wastewater, legacy wastewater, and CRL since the 2020 rule. The EPA learned about updates associated with plant operations and studies at these plants, which were originally discussed during the 2015 and 2020 rules.

The objectives of these meetings were to gather general information about coal-fired power plant operations; pollution prevention and wastewater treatment system operations; ongoing pilot or laboratory scale study information for FGD wastewater treatment; BA system performance, characterization, and quantification of the overflow and purge from remote MDS installations; and treatment technologies and pilot testing associated with CRL and legacy wastewater. The EPA used this information to supplement the data collected in support of the 2015 and 2020 rules.

3. Voluntary CRL Sampling

In December 2021, the EPA invited eight steam electric power companies to participate in a voluntary program designed to obtain data to supplement the wastewater characterization data set for CRL. The EPA requested these data from facilities believed to have constructed new landfills pursuant to the 2015 CCR rule. Six power companies chose to participate in this program. The EPA incorporated these data into the CRL analytical dataset used to estimate pollutant loadings. More information on estimated CRL pollutant loadings is available in section 6 of the Supplemental TDD.

4. Electric Power Research Institute Voluntary Submission

The Electric Power Research Institute (EPRI) conducts industry-funded studies to evaluate and demonstrate technologies that can potentially remove pollutants from wastestreams or eliminate wastestreams using zero-discharge technologies. Following the 2015 rule, the EPA reviewed 35 EPRI reports published between 2011 and 2018 that were voluntarily provided regarding characteristics of FGD wastewater, FGD wastewater treatment pilot studies, BA transport water characterization, BA handling practices, halogen addition rates, and the effect of halogen additives on FGD wastewater. For this supplemental rule, EPRI provided an additional 25 reports generated since 2018. The EPA used the information in these reports to inform treatment technology performance and to update methodologies for estimating costs and pollutant removals associated with candidate treatment technologies.

5. Meetings With Trade Associations

In 2021 and 2022, the EPA met with the Edison Electric Institute and the American Public Power Association. These trade associations represent investor-owned utilities and community-owned utilities, respectively. They provided information and perspectives on the status of many utilities transitioning away from coal. The EPA also participated in meetings with one trade association following the 2023 proposed rule. This association requested meetings with the EPA to discuss the association's public comments.

B. Notices of Planned Participation

The 2020 rule required facilities to file a Notice of Planned Participation (NOPP) with their permitting authority no later than October 13, 2021, if the facility wished to participate in the LUEGU subcategory, the permanent cessation of coal combustion by 2028 subcategory, or in the VIP. For the permanent cessation of coal combustion by 2028 subcategory, this filing date was extended by a 2023 direct final rule to June 27, 2023. 88 FR 18440. While the facilities were not required to provide copies of the NOPPs to the Agency, the EPA nevertheless obtained a number of these filings. Some facilities provided the EPA a courtesy copy when filing with the relevant permitting authority. The Agency received notice of other filings when a state permitting authority sent new draft permits or modifications to the EPA for review. The EPA also asked some states for NOPPs after those states asked the EPA questions about the process or initiated discussions about specific plants. Environmental groups that collected some additional information about NOPPs also shared the information with EPA prior to the publication of the proposed rule.

The EPA is currently aware of NOPPs covering 94 EGUs at 38 plants. At the time of the proposed rule, four EGUs (at two plants) requested participation in the LUEGU subcategory, an additional 12 EGUs (at four plants) requested participation in the 2020 rule VIP, and the remaining 74 EGUs (at 33 plants) requested participation in the permanent cessation of coal combustion by 2028 subcategory.[24] Following the 2023 direct final rule, the EPA obtained one additional NOPP stating that two EGUs (at one plant) requested participation in the permanent cessation

[24] Plant Scherer filed a permanent cessation of coal combustion by 2028 NOPP for two EGUs and a 2020 rule VIP NOPP for the remaining two EGUs; thus, the plant count for the three groupings does not equal 38.

of coal combustion subcategory by 2028 instead of the 2020 rule VIP. The EPA notes that these counts are not a comprehensive picture of facilities' plans for two reasons. First, the EPA was unable to obtain information for all plants and states. Second, even where a facility has filed a NOPP, under the transfer provisions of 40 CFR 423.13(o)(1)(ii), it still retains flexibility to transfer between subcategories, or between a subcategory and the 2020 VIP provisions, until December 31, 2025.[25] For example, the EPA made industry profile updates to some of the 90 EGUs with corresponding NOPPs based on public comments and other power company data (*e.g.,* integrated resource planning reports). For further detail, the NOPPs the EPA is aware of have been placed in the docket along with a memorandum summarizing the information and providing record index numbers for locating each facility, entitled *Changes to Industry Profile for Coal-Fired Generating Units for the Steam Electric Effluent Guidelines Final Rule* (DCN SE11618).

C. Information from Technology Vendors and Engineering, Procurement, and Construction Firms

The EPA gathered data on the availability and effectiveness of FGD wastewater, BA handling, CRL, and surface impoundment dewatering operations and wastewater treatment technologies from technology vendors and engineering, procurement, and construction firms through presentations, conferences, meetings, and email and phone contacts. These collected data informed the development of the technology costs and pollutant removal estimates for FGD wastewater, BA transport water, CRL, and legacy wastewater.

D. Other Data Sources

The EPA gathered information on steam electric generating facilities from the DOE's Energy Information Administration (EIA) Forms EIA–860 (Annual Electric Generator Report) and EIA–923 (Power Plant Operations Report). The EPA used the 2019, 2020, and 2021 data to update the industry profile, including commissioning dates, energy sources, capacity, net generation, operating statuses, planned retirement dates, ownership, and pollution controls at the EGUs. The EPA also referenced 2022 EIA data to support the analysis of FGD halogen (bromide and iodine) loads. Finally, the EPA used a 2024 EIA study as the basis for estimating the costs of a new coal-fired steam power plant.[26]

The EPA conducted literature and internet searches to gather information on FGD wastewater treatment technologies, including information on pilot studies, applications in the steam electric power generating industry, and implementation costs and timelines. The EPA also used internet searches to identify or confirm reports of planned facility plant and EGU retirements and reports of planned unit conversions to dry or closed-loop recycle ash handling systems. The EPA used this information to inform the industry profile and identify process modifications occurring in the industry.

VII. Final Regulation

A. Description of the Options

The EPA analyzed four main regulatory options at proposal, the details of which were discussed in the proposed rule. *See* 88 FR 18824, 18837–18838 (Mar. 29, 2023). For the final rule, the EPA evaluated three main regulatory options, as shown in table VII–1 of this preamble. Option A corresponds to the proposed regulation with modifications, while Options B and C would require controls that would achieve greater pollutant reductions. All three options include the same technology basis for FGD wastewater (zero-discharge systems) and BA transport water (dry-handling or closed-loop systems), while incrementally increasing controls on CRL and legacy wastewater and removing certain subcategories as one moves from Option A to Option C. Each successive option from Option A to Option C would achieve a greater reduction in wastewater pollutant discharges. Each subcategorization is described further in section VII.C of this preamble.

1. FGD Wastewater

Under all three main options, the EPA would require zero discharge of FGD wastewater based on zero-discharge technologies and retain the 2020 FGD wastewater limitations and standards as an interim step toward achievement of zero-discharge requirements. Under all three options, the EPA would also eliminate the BAT and PSES subcategorizations for high-FGD-flow facilities and LUEGUs. Options A and B would also create a subcategory for EGUs that will permanently cease coal combustion no later than December 31, 2034, and instead of zero discharge would require discharges from these facilities to meet the 2020 rule limitations as included in their CWA permit. This subcategory modifies the proposed early adopters subcategory and is described further in section VII.C of this preamble. Under Option C, the EPA would not finalize a subcategory for those EGUs planning to cease coal combustion by December 31, 2034. Note that, for all three options, the EPA would retain the 2020 subcategory for EGUs permanently ceasing coal combustion by 2028.

2. BA Transport Water

Under all three main options, the EPA would require zero discharge of BA transport water based on dry-handling or closed-loop systems and retain the 2020 BA transport water limitations and standards as an interim step toward achievement of zero-discharge requirements. For all three options, the EPA would also eliminate the BAT and PSES subcategorizations for LUEGUs. Options A and B would also create a subcategory for EGUs that will permanently cease coal combustion no later than December 31, 2034, and instead would require discharges from these facilities to meet the 2020 rule limitations as permitted. Under Option C, the EPA would not finalize this subcategory. Note that, for all three options, the EPA would retain the 2020 subcategory for EGUs permanently ceasing coal combustion by 2028.

3. CRL

Under Option A, the EPA would establish BAT limitations and PSES for mercury and arsenic based on chemical precipitation treatment. Under Options B and C, BAT limitations and PSES would be zero discharge and the EPA would establish BAT limitations for mercury and arsenic based on chemical precipitation for discharges of unmanaged CRL. Options A and B would also create a subcategory for EGUs that would permanently cease coal combustion no later than December 31, 2034; CRL discharges from EGUs in this subcategory would be subject to case-by-case BPJ decision-making until permanent cessation of coal combustion, after which they would be subject to mercury and arsenic limitations based on chemical precipitation. Under Option C, the EPA would not finalize this subcategory.

4. Legacy Wastewater

Under Option A, the EPA would not specify a nationwide technology basis for BAT/PSES applicable to legacy

[25] The ability to transfer into the LUEGU subcategory ended on December 31, 2023.

[26] U.S. Energy Information Administration (2024). *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies,* available at: *https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.*

wastewater at this time and such limitations would be derived on a site-specific basis by the permitting authorities, using their BPJ. Under Options B and C, the EPA would establish a subcategory for discharges of legacy wastewater discharged from surface impoundments commencing closure after July 8, 2024. For such discharges, the EPA would establish mercury and arsenic limitations based on chemical precipitation.

Table VII-1. Main Regulatory Options

Wastestream	Subcategory	Technology Basis for the BAT/PSES Regulatory Options		
		A	**B (Final Rule)**	**C**
FGD wastewater	N/A	Zero-discharge systems	Zero-discharge systems	Zero-discharge systems
	High-FGD-flow facilities/LUEGUs	NS	NS	NS
	EGUs permanently ceasing coal combustion by 2028	Surface impoundments	Surface impoundments	Surface impoundments
	EGUs permanently ceasing coal combustion by 2034	2020 rule limitations as permitted	2020 rule limitations as permitted	NS
BA transport water	N/A	Dry-handling or closed-loop systems	Dry-handling or closed-loop systems	Dry-handling or closed-loop systems
	LUEGUs	NS	NS	NS
	EGUs permanently ceasing coal combustion by 2028	Surface impoundments	Surface impoundments	Surface impoundments
	EGUs permanently ceasing coal combustion by 2034	2020 rule limitations as permitted	2020 rule limitations as permitted	NS
CRL	N/A	Chemical precipitation	Zero-discharge systems	Zero-discharge systems
	Discharges of unmanaged CRL	NS	Chemical precipitation	Chemical precipitation
	EGUs permanently ceasing coal combustion by 2034	Reserved; Chemical precipitation after closure	Reserved; Chemical precipitation after closure	NS
Legacy wastewater	N/A	Reserved	Reserved	Reserved
	Legacy wastewater discharged from surface impoundments commencing closure after **July 8, 2024**	NS	Chemical precipitation	Chemical precipitation

N/A = Not applicable

NS = Not subcategorized

Note: The table above does not present existing subcategories included in the 2015 rule or the 2020 VIP for FGD wastewater. The EPA did not propose, nor is it finalizing, any changes to the existing 2015 rule subcategorization of oil-fired units, units with a nameplate capacity of 50 MW or less, or the 2020 VIP.

B. Rationale for the Final Rule

After considering the technologies described in this preamble and the TDD, as well as public comments, and in light of the factors specified in CWA sections 301(b)(2)(A) and 304(b)(2)(B) (*see* section IV of this preamble), the EPA is establishing BAT effluent limitations based on the technologies described in Option B.[27] While the EPA is establishing new BAT effluent limitations for FGD wastewater and BA transport water based on more stringent technologies than the 2020 rule, the EPA is retaining the 2020 rule BAT effluent limitations for discharges before the applicability dates for new limitations on these wastewaters.

1. FGD Wastewater

The EPA is identifying zero-discharge systems as the technology basis for establishing BAT limitations to control pollutants discharged in FGD wastewater.[28] More specifically, the technology basis for BAT is membrane filtration systems, SDEs, and thermal evaporation systems, alone or in any combination, including any necessary pretreatment (*e.g.,* chemical precipitation) or post-treatment (*e.g.,* crystallization).[29] Furthermore, where a permeate or distillate is generated from the final stage of treatment, the BAT technology basis uses a process wherein this water would then be recycled back into the plant as either FGD makeup water or EGU makeup water.[30] After considering the factors specified in CWA section 304(b)(2)(B), the record shows that this suite of technologies is technologically available, is economically achievable, and has acceptable non-water quality environmental impacts. It is the EPA's intent that these three technologies considered together constitute BAT for FGD wastewater, and the EPA concludes that this BAT basis meets the requisite statutory factors. The EPA also finds, however, that each of the individual technologies within this suite supports a BAT determination on its own.

In the following subsections, the EPA discusses its rationale for selecting three zero-discharge systems as BAT for the control of FGD wastewater, as well as how each individual zero-discharge technology supports the BAT technology basis on its own. The EPA also explains why it is not selecting a less stringent technology as BAT. For further discussion of the changes (now being finalized by the EPA) to the definition of FGD wastewater related to infrequent storm events and decommissioning wastewater, see section VII.B.5 of this preamble. For further discussion of the EPA's retention of the 2020 rule limitations as interim limitations, see section VII.C.7 of this preamble.

a. The EPA selects zero-discharge systems as BAT for FGD wastewater.

Technological availability of zero-discharge systems. At proposal, the EPA identified membrane filtration as a potential BAT on which to base zero-discharge limitations for FGD wastewater, but also solicited comment on several other zero-discharge technologies, such as thermal evaporation systems and SDEs, that the EPA thought might serve alone or in any combination as the BAT basis for a final rule.

The EPA received many comments that were specific to individual zero-discharge technologies, including both comments supporting and opposed to a finding of technological availability for these individual technologies as part of the BAT basis. Comments supporting zero-discharge limitations pointed to the large number of operating zero-discharge plants and pilot studies as evidence that more than just the best performing plant or pilot plants are using zero-discharge systems. Comments opposing such a finding primarily focused on membrane filtration, the EPA's proposed zero-discharge technology basis under the preferred regulatory option. The two concerns raised most commonly in opposition to the finding of membrane filtration availability were, first, that the EPA did not collect sufficient additional information to alter its findings in the 2020 rule regarding this technology's availability and, second, that the pilot studies and foreign plants cited by the EPA were conducted on small FGD wastewater flows that were not representative of domestic industry operations. For both membrane filtration systems and thermal evaporation systems, commenters who opposed a finding of availability also questioned whether back-end management options were available for the associated wastes from zero-discharge systems. To the extent it received comments suggesting that waste management alternatives are not available, the EPA has addressed these comments in the subsection discussing non-water quality environmental impacts, below.

After consideration of public comments and as further discussed below, the EPA is basing its determination that zero-discharge systems are available for control of pollutants found in FGD wastewater on the numerous full-scale domestic and foreign installations of zero-discharge systems to treat FGD wastewater, the large number of successful domestic and international pilot tests of zero-discharge systems on FGD wastewater, successful use of zero-discharge systems on other steam electric wastestreams, and the use of zero-discharge systems on wastestreams in many different industries besides the steam electric power generating industry. Alternatively, the EPA is basing its determination that each of the technologies that make up the suite of zero-discharge systems forming the BAT basis, standing alone, is available on the several full-scale domestic and/or

[27] The EPA is including severability language in the final rule that makes clear that if any provisions of the final rule are reviewed and vacated by a court, it is the EPA's intent that as many portions of the rule remain in effect as possible.

[28] As described in section VII.B.5 of this preamble, the EPA is also finalizing a definitional change to certain wastewaters, including FGD wastewater, that excludes discharges necessary as a result of high intensity, infrequent storm events, as well as wastewater removed from FGD wastewater treatment equipment within the first 120 days of decommissioning the equipment.

[29] While three main technologies are listed here and are used to evaluate costs and non-water quality environmental impacts, the list is not meant to exclude use of other known zero-discharge treatment processes, including FA fixation, direct encapsulation, or evaporation ponds.

[30] The 2020 rule finalized a carve out from the definition of FGD wastewater applicable to ''treated FGD wastewater permeate or distillate used as boiler makeup water.''

foreign installations of each of these technologies to treat FGD wastewater and/or the successful domestic and international pilot tests of each of these technologies on FGD wastewater. The availability of each technology standing alone is also supported by the successful use of each of these technologies on other steam electric wastestreams and/or the use of each of these technologies on wastestreams in different industries besides the steam electric power generating industry. The weight of the evidence supports the Agency's conclusion that the suite of zero-discharge systems (or each of the individual technologies alone) are available in the industry to control FGD wastewater discharges, notwithstanding certain uncertainties the EPA described in the 2020 rule about one of the technologies that form the zero-discharge BAT technology basis. Agencies have inherent authority to reconsider past decisions and to revise, replace, or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n* v. *State Farm Mutual Auto. Ins. Co.,* 463 U.S. 29, 42 (1983). A finding that zero-discharge systems are available, or that each of the zero-discharge technologies forming the BAT basis is available, is also consistent with the technology-forcing nature of BAT as described in the legislative history and legal precedents discussing this provision (*see* section IV.B.2 of this preamble).

Full-scale domestic zero-discharge systems. In the 2020 rule, the EPA rejected membrane filtration as a standalone BAT technology basis due in part to the lack of a single full-scale domestic installation, which is still the case today. In that rule, however, the EPA did not evaluate a technology basis that includes the three zero-discharge technologies that form this final rule's BAT basis.

First, the EPA notes that 40 coal-fired power plants in the United States currently (as of 2024) operate wet FGD systems and manage their wastewater to achieve zero discharge.[31] These plants achieve zero discharge using evaporation ponds, recycling of FGD wastewater, ash fixation, thermal evaporation systems (*e.g.,* falling film evaporators), or SDEs. About 19 additional plants operated zero-discharge systems for FGD wastewater since 2009 but have since retired or converted fuels such that the FGD wastewater generation, and associated zero-discharge operations, have ceased. In total, more domestic facilities operate, or have operated, zero-discharge systems than the biological treatment systems used as the 2015 and 2020 rule bases.[32] Not only are there more of these systems, but the systems for which the EPA has information have achieved continuous, long-term zero discharge.

With respect specifically to the BAT basis identified in this final rule, the EPA finds that there are four U.S. coal-fired power plants currently operating full-scale thermal and three U.S. coal-fired power plants currently operating full-scale SDE systems.[33] The full-scale domestic application of the technologies identified in the BAT basis for this final rule support the EPA's finding that the BAT technology basis is available, as that term is used in the CWA. It also supports a finding that thermal evaporation systems are technologically available on their own and that SDEs are technologically available on their own.

Full-scale, foreign zero-discharge systems and zero-discharge pilot plants. While the full-scale, domestic operation of zero-discharge systems is sufficient to determine availability of the BAT technology basis, the EPA has also identified a number of full-scale, foreign zero-discharge systems, as well as domestic and international pilot systems; these could additionally or separately support the EPA's conclusion that the BAT basis identified in this final rule is available.

In 2020, the EPA declined to find that full-scale, foreign installations of membrane filtration demonstrated the availability of that technology, in large part because the EPA had not visited these systems or obtained long-term performance data on them, and thus stated there were uncertainties around these applications that prevented a finding of availability. At the time of the 2020 rule, the Agency cited 12 foreign installations of membrane filtration systems on FGD wastewater.[34] These systems began operating as early as 2015, and all of them were designed to operate as zero-discharge systems.[35] Importantly, however, the EPA did not dispute the availability of thermal evaporation systems in the 2020 rule. This is consistent with the record, as even at the time of the 2015 rule, the EPA visited three thermal evaporation systems operating in Italy, obtaining relevant performance data on these systems, which it then used to establish BAT limitations for a voluntary incentive program based on such technology, as well as NSPS for FGD wastewater.[36]

Some commenters on the 2023 proposal reiterated the EPA's 2020 rule findings and argued that EPA has not collected sufficient new information on foreign installations of membrane filtration to reverse its 2020 findings. EPA first notes that, for this final rule, it has modified its BAT basis from proposal to consist of three zero-discharge systems (each of which was described in the proposal). Since the 2015 rule, EPA has collected information not just about membrane filtration systems abroad, but also about an additional four thermal evaporation systems and six SDE systems operating on FGD wastewater outside the United States.[37] The EPA finds that, when combined with the site visits and performance data EPA obtained on the three Italian thermal evaporation systems as part of the 2015 rulemaking, the current record is more than sufficient to determine, based on full-scale, foreign installations, that the suite of systems forming the BAT basis in this rule is available as that term is used in the CWA.

[31] One of these 40 plants, which was already achieving zero discharge of its FGD wastewater, is now installing SDE. See *https://www.woodplc.com/insights/articles/engineering-solutions-for-wastewater-treatment* (DCN SE10284).

[32] The EPA accounted for four plants operating biological treatment systems in the 2015 rule analyses (DCN SE05832) and nine plants in the 2020 rule analyses (DCN SE08629).

[33] In the 2020 rule and 2023 proposal, the EPA has continually deferred to one company's representations that, contrary to representations from the technology vendor, its membrane filtration system is a long-term pilot system rather than a full-scale installation. This is a distinction without a difference, as the EPA can rely on both full-scale installations and pilot plants in establishing BAT limitations. Therefore, the EPA addresses this system in the section on pilot systems below (even though it could arguably be used to treat the facility's entire wastestream in the future).

[34] ERG. 2020. *Technologies for the Treatment of Flue Gas Desulfurization Wastewater* (DCN SE09218); ERG. 2020. *Notes from Call with DuPont* (DCN SE08618); Beijing Jingneng Power. 2017. *Beijing Jingneng Power Company, Ltd. Announcement on Unit No. 1 of the Hbei Shuoshou Jingyuan Thermal Power Co., Ltd. Passing Through the 168-hours Trial Operation.* November 13 (DCN SE08624); Broglio, R. 2019. *Vendor FGD Wastewater Treatment Details—Doosan.* July 15 (DCN SE07107); Lenntech. 2020. *Lenntech Water Treatment Solutions. Flue Gas Desulfurization Treatment* (DCN SE08622); Nanostone. 2019. *China Huadian Jiangsu Power Jurong Power Plant FGD Wastewater Zero Liquid Discharge Project was Awarded the Engineering Star Award.* June 27 (DCN SE08623).

[35] *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering* (DCN SE11695).

[36] This information was also used as the basis for the 2015 rule NSPS for FGD wastewater.

[37] *Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering* (DCN SE11695).

Furthermore, even looking at membrane filtration itself, as the EPA noted in the 2023 proposal, the foreign membrane filtration systems discussed in the 2020 rule have continued to successfully treat FGD wastewater and achieve zero discharge since 2020. Despite commenters arguing that this additional information is not important because it does not change the overall number of plants known to operate the technology or the number of influent and effluent concentration data points collected from these plants, the EPA finds that continued operations constitute significant new information. This is because the longer each zero-discharge system operates, the less probability that some yet unknown operational difficulty will appear and the more certainty the EPA has that the technology is capable of achieving long-term zero-discharge treatment of this wastewater. Thus, foreign installations of the suite of technologies forming the BAT basis support the EPA's conclusion that the BAT basis is available as that term is used in the CWA. At the same time, use of thermal evaporation systems abroad supports a finding that thermal evaporation systems are technologically available on their own, use of SDEs abroad supports a finding that SDEs are technologically available on their own, and use of membrane filtration systems abroad support a finding that membrane filtration is technologically available on its own.

With respect to pilot studies, the 2020 rule found that pilot projects on membrane filtration did not provide sufficient long-term concentration data on which to base a finding of availability or calculate limitations.[38] Commenters on the 2023 proposal reiterated the EPA's 2020 rule findings and suggested that the EPA had not supplemented the record with enough pilot studies to reach a new conclusion on availability. The EPA disagrees. The Agency first notes that the BAT technology basis in this final rule has been updated to consist of three zero-discharge systems. When the 13 thermal pilot projects and one SDE pilot project on FGD wastewater in the record are combined with the 30 membrane filtration pilots on FGD wastewater discussed in the proposed rule (including eight pilot studies conducted since the 2020 rule), the EPA has significant evidence of the ability of this suite of systems to handle a variety of operating conditions.[39] These domestic and foreign pilots have demonstrated success removing pollutants from FGD wastewater under a number of pretreatment settings, whether performed without chemical precipitation pretreatment, with chemical precipitation pretreatment, or following biological treatment.[40] Furthermore, while some systems will not generate a clean permeate or distillate that needs to be handled, those that do will recycle this clean water source back into the plant to meet the final zero-discharge limitations. Thus, long-term pollutant removal information is no longer as relevant as it was in 2020 because the EPA is not calculating nonzero limitations in this final rule. While this discussion of pilot projects is used to support the availability of the BAT technology basis comprised of multiple technologies, the large number of successful pilot projects of membrane filtration and thermal evaporation systems also supports the EPA's finding that these individual technologies are available on their own.

In comments, one recurring criticism of the 2023 proposal was that conclusions about membrane filtration system availability should not be drawn from foreign installations and pilot plants due to their small FGD wastewater flow rates. While the EPA acknowledges that foreign installations and pilot plants may have had smaller FGD wastewater flow rates than some of the plants the Agency expects would use this technology to meet the final limitations in this rule, this does not weigh against the EPA considering them as evidence of the technology's availability because the record shows that membrane filtration systems can be readily modified to handle different flow rates. This same comment was raised as far back as the 2015 rule with respect to thermal evaporation systems. At that time, the EPA responded to comments on the scalability of zero-discharge thermal evaporation systems:

> Additionally, even if the flow rates were smaller, the fact that the technology can treat the FGD wastewater demonstrates that the system is available, and the size of the system does not matter because the system design can be scaled and designed to accommodate different flow rates.[41]

The EPA has not received information since 2015 that suggests that technologies are no longer scalable to higher flows. With respect to membrane filtration scalability, in particular, the most common system design for operating membrane filtration technologies is to place modules of these systems in parallel and simply add more and more stacks to treat higher and higher flows. Therefore, the EPA concludes that use of zero-discharge systems in smaller flow rate pilots and full-scale foreign facilities supports the finding that the BAT technology basis is available; these uses also support the EPA's finding that each of the individual technologies forming the BAT technology basis are available on their own.[42]

Application to other wastestreams. While the record above is sufficient to determine that the BAT basis of several zero-discharge systems is available, use of the BAT basis on other wastewaters also supports the EPA's finding regarding its availability. In the 2020 rule, the EPA declined to find that membrane filtration treatment of non-FGD wastewaters was sufficient to support a finding of availability. In that rule, EPA's conclusions were based on the ways in which each non-FGD wastewater appeared different from FGD wastewater. The EPA first notes that the BAT basis includes three zero-discharge systems, not just membrane filtration. When considering the success with which this suite of zero-discharge systems has operated on non-FGD wastewater that has similar characteristics to FGD wastewater, the EPA views application of these systems to such non-FGD wastewater as supporting EPA's conclusion that the suite of zero-discharge technologies identified as BAT in this rule is in fact available.

Examining all three zero-discharge systems that constitute the basis for BAT, these systems are used in full-scale applications to other wastestreams in the steam electric power sector and other industrial sectors. The domestic steam electric power sector applies

[38] The EPA nevertheless established limitations based on membrane filtration technology in the 2020 VIP.

[39] One of the systems is a long-term pilot project at one facility, which is a commercial-scale system that may have sufficient capacity to treat the full FGD wastestream moving forward. Nevertheless, because the company is still making changes to the operation of the plant's FGD system, has also pilot tested a biological treatment system, and has continued to leave the possibility of biological treatment for compliance open, the EPA defers to the company's characterization of this system as a pilot, rather than a domestic, full-scale installation.

[40] In one case, a utility conducted a successful membrane pilot even when there were significant failures in the performance of upstream pretreatment systems leading to excessive TSS passthrough to the membrane system.

[41] U.S. EPA (Environmental Protection Agency). 2015. *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments.* Part 6 of 10. Page 6–40.

[42] It is also possible that some plants may choose to treat only a slipstream of FGD wastewater with a similarly small flow rate to keep the system closed loop.

membrane filtration and thermal evaporation systems to EGU makeup water,[43] cooling tower blowdown,[44] and ash transport water.[45] Other industrial sectors with full-scale applications of membrane filtration, thermal evaporation, and SDE systems include the textiles,[46] chemical manufacturing,[47] mining,[48] agriculture, [49] oil and gas extraction,[50] food and beverage,[51] landfills,[52] and automotive industries.[53]

Information in the record indicates that there are many similarities between the FGD and the non-FGD wastestreams where zero-discharge systems have been used. In the 2020 rule record, the EPA discussed that cooling tower blowdown at steam electric power plants and desalination in oil and gas extraction were examples of where membrane filtration has been used in full-scale applications for treating high-TDS wastewaters (high-TDS being a characteristic of FGD wastewater); 85 FR 64664–64665. The 2020 rule record also established that mining wastewaters, which are high in gypsum scaling potential (another characteristic of FGD wastewater), have been successfully treated with membrane filtration applications. Finally, the 2020 rule record established that, despite the high variability in ash transport water (a third characteristic of FGD wastewater), it has been successfully treated with membrane filtration. This information indicates that membrane filtration can operate effectively on wastestreams that contain several characteristics of FGD wastewater, including high TDS, high gypsum scaling potential, and high variability.[54] The similarities of other wastewaters to FGD wastewater are also relevant when considering the successful treatment by thermal evaporation systems. Thermal evaporation systems have been used to treat mining wastewaters, oil and gas wastewaters, and landfill leachate. SDE systems have been used to treat landfill leachate. Thus, based on the information, the use of zero-discharge systems on other wastestreams supports the Agency's conclusion that the BAT basis of zero-discharge systems is available for FGD wastewater discharges. These uses also support the Agency's conclusion that membrane filtration, thermal evaporation systems, or SDE systems are each available on their own.

For all the foregoing reasons, the EPA finds that the BAT basis of zero-discharge systems is technologically available for the control of discharges in FGD wastewater. Steam electric power plants have used membrane filtration systems to achieve zero discharge of FGD wastewater internationally for years, and they have used traditional thermal evaporation systems [55] and SDEs [56] to achieve zero discharge of FGD wastewater domestically and internationally for years, as even recent electric utility reports acknowledge.[57] [58] [59] [60] The widespread use across a variety of configurations of zero-discharge systems, when supplemented with the successful domestic and international pilot tests and use of such systems on other wastewaters in many industries (including the steam electric power generating industry itself and including wastewaters with characteristics that are similar to the FGD wastestream), further supports EPA's conclusion that the suite of zero-discharge technologies identified as the BAT basis in this rule is available. While this is not necessary to support its prior availability determination, the EPA further finds that any one of the technologies making up the BAT basis for FGD wastewater is available as that term is used in the Act. For membrane filtration, availability is demonstrated through full-scale use of membrane filtration abroad and in pilot projects both domestically and abroad, as well as its application to other wastestreams. For thermal evaporation, availability is demonstrated through use of full-scale thermal evaporation systems domestically and abroad and pilot projects both domestic and abroad, as well as their application to other wastestreams. For SDE systems, availability is demonstrated through use of full-scale SDE systems domestically and abroad, as well as their use in at least one known pilot project and application to a non-FGD wastestream.

Reliance interests in connection with 2020 BAT technologies. Several commenters on the 2023 proposal criticized EPA for continuing to support implementation of the 2020 rule while simultaneously revising that rule with potentially more stringent limitations. These commenters stated that utilities relied upon materials announcing the Agency's decision to reconsider the 2020 rule and statements in the 2023 proposal which both confirmed that utilities should continue to implement the 2020 rule. Thus, in reliance, utilities claimed that they have continued to install compliant technologies and that such reliance should lead the EPA to a decision not to finalize more stringent BAT for these wastewaters. In the

[43] EPRI (Electric Power Research Institute). 2015. *State of Knowledge: Power Plant Wastewater Treatment—Membrane Technologies.* August. 3002002143.

[44] *See, e.g.,* Drake, M., Wise, S., Charan, N., Venkatadri, R. 2012. ZLD Treatment of Cooling Tower Blowdown with Membranes. *WaterWorld.* December 1. Available online at: *https://www.watertechonline.com/process-water/article/16211541/zld-treatment-of-cooling-tower-blowdown-with-membranes* (DCN SE09089); ERG. 2019. *Final Notes from Meeting with New Logic Research.* July 22. (DCN SE07231) ERG. 2019. *Final Aquatech Meeting Notes.* July 26 (DCN SE07389).

[45] *See, e.g., https://www.ge.com/in/sites/www.ge.com.in/files/GE_solves_ash%20pond_capacity_issue.pdf* (DCN SE09090).

[46] ERG. 2020. *Final Notes from Call with DuPont* (DCN SE08618).

[47] ERG. 2020. *Final Notes from Call with DuPont* (DCN SE08618); U.S. EPA (Environmental Protection Agency). 2022. *Notes from Vendor Call with Vacom on October 27, 2021.* November 14 (DCN SE10367).

[48] ERG. 2019. *Final Notes from Meeting with Pall Water.* March 5. EPA–HQ–OW–2009–0819–7613; Wolkersdorfer, C., et al. 2015. *Intelligent mine water treatment—recent international developments.* July 21 (DCN SE08581); U.S. EPA (Environmental Protection Agency). 2014. *Office of Superfund and Remediation and Technology Innovation. Reference Guide to Treatment Technologies for Mining-Influenced Water.* EPA 542–R–14–001. March (DCN SE08582); ERG. 2019. *Final Aquatech Meeting Notes.* July 26 (DCN SE07389); U.S. EPA (Environmental Protection Agency). 2022. *Notes from Vendor Call with Vacom on October 27, 2021.* November 14. (DCN SE10367).

[49] U.S. EPA (Environmental Protection Agency). 2022. *Notes from Meeting with BKT—April 9, 2021* (DCN SE10253).

[50] ERG. 2018. *Final Oasys Meeting Notes.* February 16 (DCN SE06915); ERG. 2019. *Final Aquatech Meeting Notes.* July 26 (DCN SE07389); ERG. 2019. *Final Veolia Meeting Notes.* August 30 (DCN SE07818); U.S. EPA (Environmental Protection Agency). 2022. *Notes from Vendor Call with Purestream on October 26, 2021.* November 14 (DCN SE10366); U.S. EPA (Environmental Protection Agency). 2022. *Notes from Vendor Call with Vacom on October 27, 2021.* November 14 (DCN SE10367).

[51] U.S. EPA (Environmental Protection Agency). 2022. *Notes from Meeting with BKT—April 9, 2021* (DCN SE10253).

[52] ERG. 2019. *Sanitized_Saltworks Vendor Meeting Notes—Final* (DCN SE07089); U.S. EPA (Environmental Protection Agency). 2022. *Notes from Vendor Call with Heartland on October 19, 2021.* September 26 (DCN SE10291).

[53] U.S. EPA (Environmental Protection Agency). 2022. *Notes from Meeting with ProChem—April 9, 2021* (DCN SE10254).

[54] Use of membrane filtration has since expanded into additional applications, treating wastewaters and industries beyond those where it was used at the time of the 2020 rule (*e.g.,* the food and beverage and automotive industries).

[55] The Italian thermal evaporation systems discussed first in the 2013 proposed rule have been in operation for over a decade.

[56] Spray dry absorbers, effectively the same technology as the SDE, have been in use for decades to capture the same pollutants present in FGD wastewater.

[57] ''Proven technology (considered BAT for new sources by EPA). 3+ U.S. installations and 6+ European installations by Aquatech'' (DCN SE07206).

[58] DCN SE10234.

[59] DCN SE09998.

[60] EPRI (Electric Power Research Institute). 2017. *Thermal Evaporation Technologies for Treating Power Plant Wastewater: A Review of Six Technologies.* 000000003002011665 (DCN SE06971).

alternative, some commenters recommended that such facilities reliance on, and compliance with, the 2020 rule should lead the EPA to build in additional flexibility for any more stringent BAT. Suggested flexibilities focused on subcategorization or longer timeframes for cost recovery before installation of more stringent technologies.

The EPA agrees that such reliance interests should be considered.[61] The EPA disagrees, however, with commenters who suggested these interests mean the Agency must retain only the 2020 limitations in all cases. First, no NPDES permittee has certainty of its limitations beyond its five-year NPDES permit term, as reissued permits must incorporate any newly promulgated technology-based limitations as well as potentially more stringent limitations necessary to achieve water quality standards. *See* 40 CFR 122.44(a) and (d). The statute is designed for both technology-based and water quality-based effluent limitations to be revisited in each permit and, when necessary, revised consistent with these provisions and in light of the goal of ultimately eliminating pollutant discharges from point sources into WOTUS. *See* CWA section 101, 33 U.S.C. 1251.

Moreover, the EPA has included enough time for facilities to build in any reasonable reliance interest. As discussed in section VII.E of this preamble, the Agency is finalizing a ''no later than'' date for the new FGD wastewater BAT limitations of December 31, 2029. Having a ''no later than'' date approximately five-and-a-half years following promulgation allows facilities to rely on permitted limitations for the remainder of any permit existing as of the effective date of this final rule.

Third, the EPA has considered the arguments that facilities have unrecoverable costs, particularly for biological treatment systems that the final rule may render obsolete, by evaluating both the existing costs of the 2020 rule and the costs of this final rule together in the IPM analysis. As discussed in sections VII.F and VIII.C, the EPA uses IPM to analyze electric sector impacts.[62] IPM shows small impacts across the industry and leads the EPA to the conclusion that even the cumulative cost of the two technologies is economically achievable (this concept is explained in section VII.F of this preamble). Where more stringent technologies are available, are economically achievable, and have acceptable non-water quality environmental impacts as zero-discharge systems do here, the fact that facilities may have to spend more to supplement or replace existing treatment systems, even relatively new ones, is not a sufficient reason on its own to reject selection of the technology.

Lastly, to the extent that the facilities claiming to be most impacted by having to add treatment are those that will be permanently ceasing coal combustion by 2034, the EPA has created a new subcategory for these facilities that would allow them to continue to meet only the 2020 BAT limitations and thereby avoid recovering the costs of two treatment systems (*i.e.,* biological treatment and a zero-discharge system), each one designed to meet the requirements of the 2020 or 2024 rules, over the facility's short remaining useful life. EPA anticipates that approximately nine EGUs may be able to avail themselves of this subcategory with respect to FGD wastewater.[63]

Economic achievability of zero-discharge systems. The EPA finds that the costs of zero-discharge systems for control of FGD wastewater are economically achievable. The 2020 rule cited the increased cost of membrane filtration as compared to the selected technology basis as a reason for rejecting membrane filtration[64] but did not find that the costs of membrane filtration were not economically achievable at that time. The EPA also declined in the 2020 rule to establish BAT based on thermal evaporation systems, which the Agency stated were 2.4 times the costs of the 2020 BAT technology basis of chemical precipitation plus low-residence-time-reduction biological treatment and 1.04 times the cost of membrane filtration. The Agency said that these costs were unreasonably high, and it cited this finding, together with the costs that the industry was facing due to other EPA rules, to reject thermal technologies as not economically achievable.

After updating the cost analysis and IPM modeling for the final rule, the EPA finds that the costs of the BAT basis of zero-discharge systems for FGD wastewater are economically achievable for the industry, as discussed further below and in sections VII.F and VIII. Furthermore, the EPA notes that the estimates in IPM are conservative with respect to FGD wastewater. To the extent that costs would have been lower at six plants had the EPA used certain CBI costs for thermal evaporation systems in its primary cost analysis, the economic impacts modeled in IPM at these plants are overestimated.[65]

Non-water quality environmental impacts of zero-discharge systems. The EPA finds that the non-water quality environmental impacts of zero-discharge systems are acceptable.

The EPA proposed to find that the non-water quality environmental impacts of membrane filtration are acceptable. Specifically, the EPA proposed to reverse findings from the 2020 rule regarding FA use to encapsulate the brine generated by membrane filtration. The EPA also solicited comment on the non-water quality environmental impacts of other zero-discharge systems that might be used as a BAT technology basis.

Some commenters raised concerns relating to the non-water quality environmental impacts of zero-discharge systems. Specifically, commenters expressed concerns that the EPA had incorrectly evaluated FA availability because it did not use the most recent EIA data (which demonstrates that there is not enough FA available for brine encapsulation), did not use proper brine generation and encapsulation blending rates, and did not account for the costs of lost FA sales. Other commenters questioned the technological availability of one method of handling the solid waste generated from zero-discharge technologies—brine encapsulation—claiming that it has not been demonstrated to adequately retain pollutants in a landfill and, furthermore, that a particular form of brine encapsulation (paste encapsulation) has not been demonstrated and may not satisfy current disposal requirements. Finally, commenters claimed that pollutants in encapsulated brines and unencapsulated salt crystals could be

[61] The Supreme Court has held that, while an agency may change policies based upon a reasoned explanation, where a prior policy has engendered serious reliance interests, those interests must be taken into account. *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. at 515 (citation omitted).

[62] While this modeling illustrates how the sector may comply with the rule, the EPA notes that the rule does not require any facilities to close.

[63] Additional EGUs are projected to participate in this subcategory for BA transport water and CRL as discussed in the sections below.

[64] While the relative costs of technologies differ from plant to plant, the 2020 rule acknowledged, and additional information obtained during the 2022 information collection confirms, that, in some cases, technologies such as membrane filtration may be less costly than biological treatment at individual plants even where, on average, they would be more expensive to the industry as a whole.

[65] To the extent that cost estimates for individual technologies are roughly of the same magnitude as indicated in the primary cost analysis, these costs would not be expected to alter the findings on economic achievability, even if the Agency were to rely on any one of the zero-discharge technologies as a standalone BAT basis.

remobilized in a landfill setting or could damage the landfill-liner system. While some comments argued these disposal issues spoke to availability of the zero-discharge technology, the EPA views this rather as a non-water quality environmental impact (solid waste disposal issue) that it must consider. After considering these comments and the record, the EPA finds that the non-water quality environmental impacts of zero-discharge systems are acceptable.

With respect to comments on FA availability, the EPA agrees with commenters that it should evaluate the most recent EIA data, brine generation data, and data on encapsulation blends. Therefore, the EPA has updated its analysis to consider the most recent information in *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* (DCN SE11692). As noted in that document, FA sold for beneficial use fluctuates from year-to-year, but over the last five years the amount sold would still be less than the amount available for sale even after assuming that every plant uses FA to encapsulate brine from an FGD wastewater and/or CRL treatment system. Thus, the EPA does not expect that under worst-case scenarios the use of FA to encapsulate brine would hamper the fly ash sales market, let alone constitute an unacceptable non-water quality environmental impact.

Furthermore, the assumption that all facilities use membrane filtration and generate a brine for encapsulation represents a conservative estimate on FA usage. The EPA has updated its cost estimates as discussed in section VIII and section 5 of the TDD. These revised cost estimates consist of least-cost analysis across the various zero-discharge systems. Part of this update also included adjustments to better account for the amount of FA available for encapsulation, brine generation rates, and brine encapsulation blends, all to respond to commenters and improve the accuracy of the Agency's analysis. The EPA finds that the now higher costs of membrane filtration lead thermal and SDE systems to be a less costly option at many plants. This finding is consistent with cost information received from some companies showing that membrane filtration would not be the least-cost technology. As a result of this analysis selecting non-membrane systems at a number of plants, the assumptions of FA usage presented above can be seen as a likely worst-case scenario. To the extent that FA sales would be even less hampered than the scenario already found to be acceptable above, it would only further support the Agency's conclusion that FA use in brine encapsulation has acceptable non-water quality environmental impacts. For a further discussion of EPA's revised cost estimates, see section 5 of the TDD.

With respect to comments about potential remobilization of pollutants from brine encapsulation and demonstration of paste encapsulation; as far back as the 2015 rule, the EPA pointed to multiple waste-handling alternatives that were being employed by facilities with zero-discharge systems. Some facilities at that time used the brine generated by thermal systems to condition ash for disposal. In the 2020 rule record, the EPA discussed facilities that directly engage in FA fixation of the FGD wastewater for this purpose, skipping the volume reduction step that a membrane or thermal system would offer (see section 4.1.5 of the 2020 TDD, DCN SE08650). When commenters express concern that contaminants from encapsulated brines could be remobilized, these comments assume less processing than EPA contemplates. The commenters reference situations where FGD wastewater or brine are merely used to condition ash without employing the further pozzolanic reactions that the EPA expects to occur in the full encapsulation process and that EPA included in its cost estimates of zero discharge. Encapsulation studies demonstrate that concentrations of leachate pass leachate toxicity tests and are of lower concentration than raw FGD wastewater. Encapsulation would also result in far less remobilization than exiting ash conditioning practices. Furthermore, to the extent that the EPA considered and discussed paste encapsulation, it was as a potentially cost-saving alternative to these conditioning and encapsulation techniques that are already well-demonstrated. Thus, to the extent that it is a less costly solid waste management alternative, it only provides the promise of cost savings compared to the EPA's estimates, but the EPA does not rely on this particular form of brine encapsulation in determining that solid waste disposal issues as a whole have acceptable non-water quality environmental impacts.

Even if brine encapsulation had not been adequately demonstrated as a solid waste handling practice, other solid waste handling alternatives are available. For example, facilities in the 2015 and 2020 rule records took the brine generated from a thermal system all the way down to a salt crystal using a crystallizer (DCN SE11695). The EPA evaluated these costs in the *FGD Wastewater, CRL, and Legacy Wastewater Zero Discharge Treatment Technologies Costs, Loadings, and Non-Water Quality Environmental Impacts* file (DCN SE11709) as an alternative and found it would increase annualized costs by three percent. These slightly higher overall costs would still be economically achievable.[66]

With respect to comments about remobilization of pollutants, the EPA agrees with commenters that pollutants in a landfill can be remobilized through percolation of rainwater through the disposed solid wastes. These solid wastes would include not only any encapsulated brines but also certain solids and salt crystals that would be disposed of following use of some thermal and SDE alternatives where no brine is generated. Here, absent the pozzolanic reactions from either ash conditioning or encapsulation, remobilization of pollution is more possible as rainfall percolates through these disposed solids. Nevertheless, proper landfill management is designed to reduce infiltration of water through a landfill and to capture leachate that makes it to the liner at the bottom of a landfill. The EPA received no comments that the facilities already generating these solids and salts have failed to properly operate their landfills such that contaminants were remobilized into the environment. Even where remobilization can reduce the overall effectiveness of the pollution treatment systems, as discussed in section VII.B.3 of this preamble, the EPA is also finalizing zero-discharge limitations for CRL during the life of the plant, unless they are discharges of unmanaged CRL.[67] This is designed to further ensure that these pollutants are kept in the landfill to the maximum extent possible rather than remobilized and released into the environment.

Many of the facilities presented in the record as having zero-discharge systems have also successfully disposed of conditioned ash or FGD solids in landfills for years. The record supports that a properly designed, installed, and maintained landfill can operate as intended. As the EPA learned during implementation of the CCR rule, many

[66] Facilities could also consider deep-well injection of their brine. The EPA found that these costs on a nationwide basis would be three times the costs of encapsulation, and so are unlikely to be pursued by most facilities, though this too would constitute an alternative disposal practice available for the management of brine.

[67] Note that the EPA is finalizing zero-discharge limitations for CRL, except as specified in the subcategories discussed in sections VII.C.4 and C.5. Where lined WMUs collect and treat CRL to zero-discharge standards during a facility's operation, permeate and distillate can be used to condition CCR for disposal in these WMUs.

historical CCR landfills may suffer from the lack of an adequate liner system. However, the Agency has no evidence that, where liners are properly designed, installed, and maintained, they are incompatible with the additional pollutants in FGD wastewater that zero-discharge systems would capture.[68]

Finally, the EPA finds that, even to the extent that there are any negative non-water quality environmental impacts, the positive non-water quality environmental impacts outweigh the negative ones. In particular, the EPA estimates that there are significant decreases in air pollution and water withdrawals [69] as a result of this rule. While the rule is not being promulgated to reduce these impacts, these resulting non-water quality environmental impacts further support the Agency's conclusion that zero-discharge systems for FGD wastewater are BAT.

b. The EPA rejects less stringent technologies than zero-discharge systems as BAT for FGD wastewater.

Except for the new permanent cessation of coal combustion by 2034 subcategory discussed in section VII.C.4 of this preamble, and for discharges before the applicability dates of the new zero discharge-requirements in this final rule, the EPA is not selecting chemical precipitation followed by a low hydraulic residence time biological treatment including ultrafiltration, as the BAT technology basis. BAT is the ''gold standard'' for controlling water pollution from existing sources, and the Supreme Court has explained that BAT must achieve ''reasonable further progress'' toward the CWA's goal of eliminating pollution. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1003, 1006 (citing *Nat'l Crushed Stone* v. *EPA,* 449 U.S. 64, 75 (1980)). The record shows that the 2020 rule industrywide BAT technology basis for FGD wastewater removes fewer pollutants than the zero-discharge BAT technology basis identified in this final rule that has been found to be technologically available, be economically achievable and have acceptable non-water quality environmental impacts.[70] Similarly, except for the permanent cessation of coal combustion by 2028 subcategory discussed in section VII.C.3 of this preamble, the EPA is not identifying the less stringent (and previously rejected in the 2015 and 2020 rules) technologies of surface impoundments or chemical precipitation, as these technologies too will remove fewer pollutants than the BAT technology basis in this rule.

2. BA Transport Water

The EPA is identifying the zero-discharge systems of dry-handling or closed-loop systems as the technology basis for establishing BAT limitations to control pollutants discharged in BA transport water.[71] Specifically, dry-handling systems include both waterless air-cooled conveyor systems and pneumatic systems, as well as under-boiler mechanical drag systems (*e.g.,* submerged chain conveyors) and submerged grind conveyors (*e.g.,* compact submerged conveyors), which use quench water to cool the ash but immediately remove the ash without generating BA transport water. Closed-loop systems consist of remote mechanical drag systems that actively sluice the ash (*i.e.,* transport the ash with water) and are paired with any necessary storage tanks, chemical addition systems, and/or RO treatment necessary to fully recycle BA transport water except during high intensity, infrequent storm events as discussed below.[72] The EPA finds that these technologies are technologically available, are economically achievable, and have acceptable non-water quality environmental impacts after evaluating the factors specified in CWA section 304(b)(2)(B).

In the 2020 rule, the EPA rejected dry-handling or closed-loop systems as the BAT technology basis in favor of high-recycle-rate systems with a site-specific purge allowance of up to 10 percent of the BA transport water system's volume to address four potential purge needs.[73] The EPA justified this change in BAT due to process changes plants were making to comply with the CCR regulations, as well as the additional costs of dry-handling or closed-loop systems. In the 2023 proposal, the EPA reevaluated the four asserted purge needs relied upon in establishing the 2020 purge, and for each asserted purge need, the Agency explained why the record no longer supported that these purges should be part of the BAT technology basis. As a result, the EPA proposed returning to the dry-handling or closed-loop systems that served as the BAT technology basis in the 2015 rule.

The EPA received comments both supporting and criticizing the proposed return to the BAT basis of dry-handling or closed-loop systems selected in the 2015 rule. Comments supporting the EPA's proposal to return to the 2015 BAT technology basis for BA transport water focused on the lack of evidence in the record of facilities with a demonstrated need to purge BA transport water. These comments also focused on the legal standard that BAT represents the best performing plant, arguing further that the EPA has never disputed that the best performing plant can achieve zero discharge. Comments opposing the return to the 2015 rule standard reiterated the four potential purge needs discussed in the 2020 rule. In the alternative, these commenters asked the EPA to formulate flexibilities for purges that in practice might be more or less flexible than the site-specific 10 percent volumetric purge allowance arrived at in the 2020 rule.

Commenters also responded to the EPA's solicitation about the potential disparity between the purges from closed-loop systems and the purges from under-boiler ''dry'' handling systems that still use quench water. These comments asked EPA not to further regulate quench water from under-boiler systems because the water is not used to transport ash and these facilities had relied on the quench water from dry-handling systems being treated as a ''low volume waste source'' rather than BA transport water.

After considering all public comments and the EPA's extensive record in light of the statutory factors, and as explained below, the EPA finds that dry-handling or closed-loop systems are available and economically achievable, and that they have acceptable non-water quality environmental impacts. Therefore, the

[68] In contrast, FGD gypsum is already removed from FGD wastewater before discharge and is known to loosen clay soils which sometimes form the base of older landfills designed without composite liners.

[69] Reduced water withdrawals could also lead to reduced impingement and entrainment.

[70] In contrast, nothing in the record or public comments indicates that chemical precipitation plus low hydraulic residence time biological reduction has ceased to be available, be economically achievable, and have acceptable non-water quality environmental impacts for discharges before the applicability dates of the new, more stringent limitations of this rule.

[71] As described in section VII.B.5 of this preamble, the EPA is also finalizing a definitional change to certain wastewaters, including BA transport water, that excludes discharges necessary as a result of high intensity, infrequent storm events, as well as wastewater removed from ash handling equipment within the first 120 days of decommissioning the equipment.

[72] In addition to remote MDSs, non-BAT technologies include many dewatering bins (also known as hydrobins), and surface impoundments may also have the flexibility to operate as closed-loop systems. Like remote MDSs, the latter systems may need to install chemical addition systems (acid, caustic, and/or flocculants), RO systems, and/or additional storage tanks to operate as fully closed loop.

[73] The four asserted purge needs related to precipitation, maintenance, water chemistry, and water balance.

EPA is selecting dry-handling or closed-loop systems as the BAT technology basis for BA transport water but is retaining the 2020 rule limitations for discharges before the applicability dates of the new zero-discharge requirement.

In the first subsection immediately below, the EPA discusses its rationale for selecting dry-handling or closed-loop systems as the BAT technology basis for BA transport water. In the following subsection, the EPA explains why it is not selecting less stringent technologies than dry-handling or closed-loop systems as the BAT technology basis for BA transport water. In the final subsection, the EPA discusses the definition of BA transport water and why, in light of the record, it declines to change how under-boiler ''dry'' systems with a discharge are regulated. For further discussion of the definitional changes to BA transport water that are being finalized with respect to high intensity, infrequent storm events, as well as decommissioning wastewater, see section VII.B.5 of this preamble. For further discussion of the EPA's retention of the 2020 rule limitations as interim limitations, see section VII.C.7 of this preamble.

a. The EPA selects dry-handling or closed-loop systems as BAT for BA transport water.

Technological availability of dry-handling or closed-loop systems. Based on the record, the EPA finds that dry-handling or closed-loop systems are technologically available. At the time of the 2020 rule, the EPA estimated that more than 75 percent of plants already employed dry-handling systems or wet-sluicing systems in a closed-loop manner, or they had announced plans to switch to such systems soon. Some of these systems have been in use since the 1970s, and today, most facilities have installed one or more such systems.[74] The high percentage of plants employing these systems indicates that they are technologically available.

In the 2015 and 2020 rule preambles, the EPA discussed the widespread use of dry-handling systems for control of BA transport water servicing about 200 EGUs at over 100 plants. In the 2020 rule, the EPA also discussed advances in dry BA handling systems. Specifically, the Agency discussed a newer technology called submerged grind conveyors (one example of which is called a compact submerged conveyor). At the time, compact submerged conveyors were known to be installed and in operation at two plants. The EPA has since learned that an additional plant has installed compact submerged conveyors.[75] [76] In addition to the increased use of compact submerged conveyors, a higher number and broader array of dry-handling systems are currently in place than the EPA originally forecasted. For example, as indicated in the 2020 rule record, one utility commented that it had space constraints at a facility that would preclude the installation of a compact submerged conveyor, and the EPA thus projected that this facility would employ a high recycle rate system under the 2020 rule. After the 2020 rule, however, that utility ultimately installed a different dry-handling system—which highlights the broad array of dry-handling options available for coal-fired power plants, regardless of their configuration. Even where space constraints may prohibit certain dry systems, a plant could use a pneumatic system, albeit at a somewhat greater cost. The 2020 rule record included information on 50 pneumatic installations from as early as 1992. Given that BAT is to reflect the best performing plant in the field, *Kennecott* v. *EPA,* 780 F.2d at 447, and that the facts in the record support the use of dry-handling technology to achieve zero discharge of BA transport water, it is likely the EPA could have selected dry-handling systems as the sole technology basis for control of BA transport water. Nonetheless, as it did in the 2015 rule, the EPA is also identifying closed-loop systems as a BAT technology basis for controlling discharges of BA transport water, given that a limited number of plants may find that option to be more attractive due to space constraints and lower costs when compared to a pneumatic system.

After the 2015 rule and during the 2020 rulemaking, certain industry representatives argued that there are challenges to operating a closed-loop BA handling system in a truly zero-discharge manner. They argued that closed-loop systems, including remote MDS and dewatering bins, cannot maintain fully closed-loop operations due to chemistry issues or water imbalances in the system, such as those that might occur from unexpected maintenance or large precipitation events. Even accounting for these issues, however, the 2020 rule did not find that closed-loop systems are not technologically available. Information in the EPA's 2020 rule record indicated that plants can operate their closed-loop systems to achieve zero discharge, although this could require some process changes and their resulting costs. Instead, the Agency rejected this technology as a basis for BAT based process changes happening at plants to comply with the CCR regulations (addressed further below), while also noting the additional costs over the 2015 rule's estimates. As explained below, the record indicates that closed-loop BAT handling systems are economically achievable. See section VIII of this preamble for a further discussion of costs associated with the closed-loop system technology basis.

In the 2020 rule, the EPA discussed four potential challenges with maintaining closed-loop systems: (1) managing non-BA transport water inflows, (2) managing precipitation-related inflows, (3) managing unexpected maintenance events, and (4) maintaining water system chemistry. The 2023 proposal discussed these issues at length, including why EPA did not view them as a basis for rejecting zero-discharge requirements. As explained in the proposal and further discussed below, based on the current record, the EPA continues to view none of these previously discussed challenges as providing a basis for rejecting closed-loop systems as not technologically available, although these issues may in certain circumstances require a plant to incur additional costs (which are found to be economically achievable) or to have an infrequent precipitation-related discharge (which would be addressed by the definitional changes the EPA is finalizing in this rule).

First, in 2020, the EPA stated that managing non-BA transport water inflows had the potential to result in water imbalances within a closed-loop system. In the 2023 proposal, the EPA found that closed-loop systems can be sized to handle additional wastestreams. The EPA received comments reiterating the 2020 rule findings; however, none of these comments provided specific data or information demonstrating that even one system cannot handle non-BA transport water inflows. Thus, EPA is maintaining its finding from proposal that a purge in response to water imbalance due to management of other wastestreams is not necessary.

Second, in 2020, EPA stated that managing precipitation-related inflows had the potential to result in water imbalances in the BA handling system. At proposal, EPA found that precipitation-related inflows can be

[74] One vendor estimates that only seven ash conversions remain in the entire industry.

[75] Some utilities have even suggested that the discussion of compact submerged conveyors in the final 2020 rule preamble and additional compliance timeframes have led them to consider these newer dry systems rather than a previously contemplated high-recycle-rate/closed-loop system.

[76] *Final Burns & McDonnell Meeting Notes* (DCN SE10248).

adequately managed with design improvements, including the use of roofing where appropriate. The 2015 BAT technology basis and 2020 rule remote MDS technology designs included covers to avoid collecting precipitation, and the costs for covers were included in the associated cost analysis. The EPA received comments on the 2023 proposal reiterating the 2020 rule findings; however, none of these comments provided specific data or information demonstrating that even one system cannot handle common precipitation-related inflows.[77] To the extent that a plant experiences precipitation-related inflows as a result of a 10-year storm event of 24-hour or longer duration (*e.g.,* a 10-year, 30-day storm event), the EPA is finalizing a definitional change discussed in section VII.B.5 of this preamble.

The 2020 rule mentioned a third previously discussed challenge to operating a remote MDS as a closed-loop system: the possibility of infrequent maintenance events that might fall outside the 2015 rule exclusion of ''minor maintenance'' and ''leaks'' from the definition of BA transport water. EPRI[78] [79] listed several such maintenance events; most were expected to occur less than annually. EPRI provided information about the estimated frequency and volume of water associated with each maintenance event; however, EPRI did not provide information about a specific remote MDS unable to manage these maintenance events with existing maintenance tanks. In the 2023 proposal, the EPA found that maintenance could be managed within a closed-loop system. Furthermore, even where maintenance wastewater volumes are too large to be managed in existing maintenance tanks, utilities can, at additional cost, lease storage tanks for short-term maintenance where these infrequent maintenance events are foreseeable. Commenters did not provide any information on maintenance activities that would require a purge if facilities properly planned and executed regular operation and maintenance (O&M). Thus, the EPA is maintaining its finding from proposal that a purge of BA transport water for maintenance is not necessary.

The final engineering challenge discussed in the 2020 rule record with respect to closed-loop systems was the need to maintain water system chemistry. The 2020 rule discussed potentially problematic system chemistries, such as extreme acidic conditions, high scaling potential, and the buildup of fine particulates that could clog pumps and other equipment. The 2015 closed-loop system BAT design basis included a chemical addition system to manage these system chemistries, as does the BAT basis in this final rule. In particular, corrosivity can be managed through pH adjustment, scaling can be managed with acid and/or antiscalants, and fines can be further settled out with polymers and other coagulants. EPRI has documented that some systems have gone slightly further, pairing the chemical addition systems with changes in operations, such as higher flow rates or longer contact time. Some commenters on the 2023 proposal suggested that systems would not be able to manage these chemistry problems but did not provide information supporting this assertion. In the absence of information, the EPA finds that, even assuming that the previously mentioned strategies would not apply at a given plant, the same slipstream of purge allowed under the 2020 rule could be treated with RO and recycled back in as clean makeup water. The EPA has considered these additional costs as discussed in sections VII.F and VIII, and outside the additional cost (which is found to be economically achievable), there is no record evidence that this chemistry-related challenge cannot be overcome with reasonable steps. Therefore, this concern does not provide a basis for rejecting closed-loop systems as BAT.

For all the foregoing reasons, the EPA finds that the record indicates that dry-handling or closed-loop systems are technologically available for control of discharges in BA transport water.

Economic achievability of dry-handling or closed-loop systems. The EPA finds that the costs of dry-handling or closed-loop systems are economically achievable. In the 2020 rule, the EPA cited the costs of closed-loop systems as an additional basis for selecting high recycle rate systems. In the 2020 rule, the EPA noted that it had ''conservatively'' estimated costs of $63 million per year based on all facilities using a remote MDS needing a 10 percent purge to be treated with RO in order to achieve complete recycle (*i.e.,* zero discharge operations). The EPA never found, however, that the additional costs to achieve zero discharge were not economically achievable.

The EPA's updated cost estimates demonstrate that, after including the costs of treating all wastestreams—including achieving zero discharge for BA transport water—the final rule would result in minimal economic impacts. (For further information, see sections VII.F and VIII.) After considering these results, the EPA finds that these additional costs are economically achievable as that term is used in the CWA.

Non-water quality environmental impacts of dry-handling or closed-loop systems. The EPA finds that the non-water quality environmental impacts associated with dry-handling or closed-loop systems for controlling BA transport water discharges are acceptable. See sections VII.G and X below for more details.

Process changes associated with dry-handling or closed-loop systems. In the 2020 rule, the EPA also rejected dry handling or closed-loop systems due to process changes happening at steam electric facilities as they moved toward compliance with the CCR regulations. The EPA stated that, as plants close their surface impoundments under the CCR regulations, they may choose to send certain non-CCR wastewaters to their BA handling system. This was said to potentially complicate their efforts to fully close their BA handling systems due to increased scaling, corrosivity, or plugging of equipment. Alternatively, a closed-loop requirement might incentivize plants to discharge their non-CCR wastes rather than send them to their BA handling systems for control, in which case they would be subject to less stringent requirements governing low volume waste sources. The EPA also suggested that requiring limitations based on closed-loop systems could result in plants using their surface impoundments longer, assuming plants cannot build alternative storage capacity and need to continue to send their non-CCR wastes to unlined impoundments.

The rationale in the 2020 rule is no longer persuasive as a reason to select high recycle rate systems rather than dry-handling or closed-loop systems because the changes happening at plants under the CCR regulations are expected to be complete by the time the final BAT limitations apply to any given plant. In particular, the final rule BA transport water requirements will be included in NPDES permits with an applicability date of no later than December 31, 2029. This is over a decade after the

[77] In one comment, a utility suggested that it could not employ roofing at its plant without jeopardizing the necessary cooling of the BA, but this plant did not provide any data showing that it could not manage this heat transfer with standard heating, ventilation, and air conditioning (HVAC) equipment.

[78] EPRI, 2018. *Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges* (DCN SE06920).

[79] EPRI, 2016. *Guidance Document for Management of Closed-Loop Bottom Ash Handling Water in Compliance with the 2015 Effluent Limitations Guidelines* (DCN SE06963).

promulgation of the 2015 CCR rule and eight years after even the revised CCR surface impoundment deadline of April 11, 2021, by which facilities were required to cease receipt of all wastes into their unlined CCR surface impoundment.[80] As of the publication of this rule, most facilities have already completed conversions of their leaking, unlined CCR surface impoundments under the CCR regulations, which means that they no longer rely on these unlined surface impoundments as part of their BA handling systems, but rather have installed systems to handle their BA transport water that do not rely on unlined CCR surface impoundments.[81]

Of the remaining unlined CCR surface impoundments that might exist following promulgation of this rule, those operating under the CCR Part A rule flexibility found in § 257.103(f)(2) must permanently cease coal combustion, and as discussed below, the EPA is retaining the subcategory for EGUs permanently ceasing coal combustion by 2028, which does not require zero discharge of BA transport water. For those unlined CCR surface impoundments that are not permanently ceasing coal combustion and are required to close for cause but where alternative capacity is technically infeasible, there is some flexibility under the CCR Part A rule allowing for a maximum timeframe of October 15, 2023, or October 15, 2024, for the surface impoundment to cease receipt of waste.[82] The 2023 and 2024 extended timeframes require EPA approval.[83] Even with these extensions, the majority of facilities will have ceased receipt of waste in its non-compliant surface impoundment and completed its conversion to a CCR regulation-compliant BA handling method (necessary to remain in operation) within a few months of the effective date of this rule. Since there are no looming deadlines and tight timeframes under the CCR regulations that would justify continued flexibility, facilities with high recycle rate systems are free to focus on transitioning those high recycle rate systems to closed-loop operations.[84] Because ash handling changes will no longer be compelled by the CCR regulations by the time this final rule is effective, the EPA concludes that there are no ''process change'' or non-water quality environmental impact reasons related to the CCR regulations that weigh against the EPA's decision to select dry-handling or closed-loop systems as the BAT basis for control of BA transport water discharges.

b. The EPA rejects less stringent technologies than dry-handling or closed-loop systems as BAT for BA transport water.

Except for the new subcategory for EGUs permanently ceasing coal combustion by December 31, 2034, and for discharges before the applicability dates for the new zero-discharge requirement of this rule, the EPA is not establishing BAT limitations based on high recycle rate systems. In the 2020 rule, the EPA reversed its decision from the 2015 rule and determined that dry-handling or closed-loop systems were not BAT. As a result, the EPA established a volumetric purge allowance (with a maximum of 10 percent of the system volume) to be determined on a case-by-case basis by the permitting authority, which required a permitting authority's BPJ analysis to determine any appropriate further control. As discussed above, the technological issues identified in the 2020 rule can be resolved, albeit at potentially additional costs, which the EPA finds are economically achievable. Furthermore, a dewatering bin or remote MDS with a purge removes fewer pollutants than the BAT basis of dry-handling or closed-loop systems, which the Agency finds is technologically available, economically achievable, and has acceptable non-water quality environmental impacts.[85] BAT is the ''gold standard'' for controlling water pollution from existing sources, and the Supreme Court has explained that BAT must achieve ''reasonable further progress'' toward the Act's goal of eliminating pollution. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1003, 1006 (citing *Nat'l Crushed Stone* v. *EPA,* 449 U.S. at 75). For these reasons, the EPA is not selecting high-rate-recycle systems as BAT.

Except for the subcategory for EGUs permanently ceasing coal combustion by December 31, 2028, the EPA is also not identifying the less stringent (and previously rejected in the 2015 and 2020 rules) technology of surface impoundments as the technology basis for BAT, as this technology would also remove fewer pollutants than the BAT basis of dry-handling or closed-loop systems, which the EPA finds is technologically available, is economically achievable, and has acceptable non-water quality environmental impacts.

c. The EPA continues to regulate discharges from some dry-handling BA systems as a low volume waste source.

As previously discussed, the final BAT technology basis for BA transport water is dry-handling or closed-loop systems. This technology basis incorporates systems that operate so as to not generate BA transport water at all (so-called ''dry'' systems), as well as systems that do generate BA transport water but recycle that transport water in a closed-loop manner so as to achieve no discharge (so-called ''wet'' systems). At proposal, EPA solicited comment on the issue of whether the final rule could create unintended consequences if discharges from a ''dry'' BA handling system are regulated differently than discharges from a ''wet'' BA handling system. Historically, discharges from a dry bottom ash handling system have not been considered transport water or BA purge water, but rather have been considered a ''low volume waste source,'' and therefore subject to their own limitations. These limitations include BPT limitations on TSS and oil and grease, as well as any more stringent BAT limitations that the permitting authority determines appropriate on a case-by-case basis using its BPJ.

In the proposal, the EPA pointed to one instance of a reported purge at an under-boiler dry-handling system that uses quench water to cool the BA but did not transport the ash with water and thus did not generate BA transport water. After soliciting comment on a number of potential modifications the Agency could make to address potential disparities between allowable purges from a wet BA handling system and a dry BA handling system, the EPA received only one comment that provided meaningful data relevant to the solicitations. Santee Cooper provided findings of a third-party analysis of the Cross facility's under-boiler dry BA handling system. Over the two years of 2021 and 2022, the BA system at Cross was fully drained 10 times and partially drained 29 times for maintenance. Historically, BA contact water such as that discharged at Cross has been treated as a low volume waste source.

[80] 40 CFR 257.101(a)(1).

[81] *See, e.g., https://www.epa.gov/coalash/coal-combustion-residuals-ccr-part-implementation.*

[82] 40 CFR 257.103(f)(1)(vi).

[83] Further information on the implementation of these Part A applications is available on EPA's website at: *https://www.epa.gov/coalash/coal-combustion-residuals-ccr-part-implementation.*

[84] Although the EPA estimates that fully closing the loop would be less expensive than converting to a dry-handling system, nothing would preclude a facility with a high recycle rate system from installing one of the technologically available and economically achievable dry-handling systems.

[85] In contrast, nothing in the record or public comments indicates that high-recycle-rate systems ceased to be available, be economically achievable, and have acceptable non-water quality environmental impacts for discharges before the applicability dates of the new, more stringent limitations of this rule.

Based on public comments and a consideration of the record, the EPA is not modifying the regulations to address discharges that the EPA has historically not considered BA transport water. EPA did not receive any information to call into question its previous conclusions about the different characteristics of BA contact water and BA transport water, including the Agency's findings in 2015 and 2020 that BA contact water has lower pollutant concentrations than BA transport water. Moreover, no commenters provided information supporting a finding that the zero-discharge requirements in this rule could have the unintended effect of leading to more discharges of low volume waste from dry BA handling systems than would otherwise occur. Based on the limited information provided in comments, EPA concludes no changes to the regulatory treatment of purges from a dry BA handling systems are warranted, and they will continue to be regulated as low-volume wastes.[86]

Aside from the under-boiler BA handling systems (''dry-handling'' systems) that the EPA solicited comment on, some commenters also responded to EPA's solicitations by suggesting that purges from remote BA handling systems (''closed-loop'' systems) should continue to be allowed to avoid creating disparities between dry-handling and closed-loop systems.[87] Comments in this vein tended to be very generalized and did not provide any meaningful reason for EPA to change direction from its proposal, with the exception of the EPA's definitional change described in section VII.B.5 of this preamble.

3. CRL

Except for the subcategory for discharges of unmanaged CRL, the EPA is identifying zero-discharge systems as the technology basis for establishing BAT limitations to control pollutants discharged in CRL.[88] More specifically, as with FGD wastewater, the technology basis for CRL is membrane filtration systems, SDEs, and thermal evaporation systems alone, or in any combination, including any necessary pretreatment *e.g.,* chemical precipitation) or post-treatment (*e.g.,* crystallization).[89] Furthermore, where a permeate or distillate is generated from the final stage of treatment, the technology basis is a process wherein this water would then be recycled back into the plant as either FGD makeup water or EGU makeup water.[90] After evaluating the factors specified in CWA section 304(b)(2)(B), the record shows that these technologies are available, are economically achievable, and have acceptable non-water quality environmental impacts. For discussion of the subcategory for discharges of unmanaged CRL, see section VII.C.5.

Based on the BAT technology basis identified, the EPA is establishing zero-discharge limitations for CRL, as it does for FGD wastewater. However, because CRL is different from FGD wastewater in that it is expected to continue to be generated and discharged following even the retirement of the plant, the EPA is also using the BAT technology basis identified to establish nonzero numeric limitations following a plant's eventual retirement—limitations based on membrane filtration for CRL permeate and limitations based on thermal evaporation for CRL distillate.

In the subsection immediately below, the EPA discusses its rationale for establishing zero-discharge systems as BAT for control of CRL. In the following subsection, the EPA explains why it rejected less stringent technologies as BAT. In the final subsection, the EPA explains the rationale for establishing zero-discharge systems as NSPS for control of CRL. For further discussion of the new subcategories for permanent cessation of coal combustion by 2034 and discharges of unmanaged CRL, see section VII.C of this preamble. For further discussion of the definitional change to CRL that is being finalized with respect to high intensity, infrequent storm events, see section VII.B.5 of this preamble.

a. The EPA selects zero-discharge systems as BAT for CRL.

Technological availability of zero-discharge systems. Although the EPA's preferred option at proposal was to identify BAT based on chemical precipitation, it solicited comment on a zero-discharge requirement based on other technologies as well, including the same technologies identified as the BAT basis for control of FGD wastewater in this rule. 88 FR 18849. The EPA received comments both for and against the availability of zero-discharge systems. Commenters favoring zero discharge of CRL pointed to the EPA's record, which shows that one facility already employs a zero-discharge thermal evaporation system to co-treat its CRL and FGD wastewater, many non-CCR landfills use zero-discharge systems to treat their leachate, and zero-discharge systems have been used to treat other wastewaters similar to CRL, including FGD wastewater. In contrast, commenters opposed to zero-discharge systems claimed that the EPA did not sufficiently evaluate such systems at proposal and further disputed EPA's findings that pollutants in CRL are similar to those in FGD wastewater.

After consideration of the comments received and evaluation of the extensive record, the EPA finds that zero-discharge systems are technologically available for control of CRL discharges. BAT is supposed to reflect the highest performance in the industry and may reflect a higher level of performance than is currently being achieved based on technology transferred from a different subcategory or category, bench scale or pilot plant studies, or foreign plants. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1006; *Am. Paper Inst.* v. *Train,* 543 F.2d at 353; *Am. Frozen Food Inst.* v. *Train,* 539 F.2d at 132. The EPA disagrees with commenters who suggested the Agency had not sufficiently evaluated zero-discharge options at proposal and instead agrees with commenters that the best-performing plant treating CRL domestically in this industry is achieving zero discharge. At proposal, the EPA discussed a thermal evaporation system that has achieved zero discharge of CRL and FGD

[86] Furthermore, the EPA notes that the resulting average annual discharge of about 600,000 gallons per year of BA contact water at Cross results in small pollutant loadings in both relative and absolute terms. Contrast this to the three million gallons *per day* of BA transport water and the relative reduction in water volumes alone, not accounting for the lower pollutant concentrations of BA contact water, mean that the pollutant discharges are reduced by over 99.9 percent.

[87] For context, the requested purges from remote systems operating as high-recycle-rate rather than closed-loop systems are often in the range of 50,000 to 100,000 gallons *per day,* an amount far greater than the amounts of BA contact water (a low-volume waste source with fewer pollutants) discharged in the one dry-handling facility for which the EPA has information on purges.

[88] As described in section VII.B.5 of this preamble, the EPA is also finalizing a definitional change to certain wastewaters, including CRL, that excludes discharges necessary as a result of high intensity, infrequent storm events.

[89] While three main technologies are listed here and are used to evaluate costs and non-water quality environmental impacts, the list is not meant to exclude use of FA fixation, direct encapsulation, evaporation ponds, or other zero-discharge treatment options where a facility uses these technologies to meet the zero-discharge standard established in this rule.

[90] The 2020 rule finalized a carve out from the definition of FGD wastewater applicable to ''treated FGD wastewater permeate or distillate used as boiler makeup water.'' The EPA is making the equivalent change to the definition of CRL for the same reasons the change was made to the definition FGD wastewater and to support consistency across these two zero-discharge wastewater streams. *See* 85 FR 64675. No corresponding change is necessary for use to condition CCR destined for disposal where the disposal would be subject to the same zero-discharge limitations.

wastewater since 2015.[91] [92] The record also includes two domestic pilot studies on CRL: one using membrane filtration and another using membrane filtration with SDE. Furthermore, the proposed rule record included information on treatment of non-CCR landfill leachate, including one thermal technology vendor with full-scale installations, one thermal technology vendor with a pilot study, and two installations of membrane filtration with SDE.[93] The successful use of these systems at non-CCR landfills is relevant to CRL because CRL contains the same pollutants as found in these landfills (*e.g.,* mercury, arsenic, selenium, nitrates), and indeed non-CCR landfills have potentially even more challenging characteristics that these systems are able to handle. In particular, these systems have proven able to successfully treat the same pollutants found in CRL, in addition to treating potentially more challenging organic pollutants and managing more challenging biological fouling agents found in non-CCR landfill leachate that are either absent from, or present in lower concentrations in, CRL. Since the absence of these pollutants and fouling agents make treatment simpler, these differences support the EPA's finding of technological availability.

Finally, since the record indicates that CRL is similar to FGD wastewater—which the record demonstrates can be effectively treated using zero-discharge systems—the EPA also independently relies on the record evidence discussed in section VII.B.1 of this preamble above and technology transfer from FGD wastewater to support its conclusion that zero-discharge systems are available for controlling CRL discharges. The EPA may rely on technology transfer to establish technology-based limitations such as those in this rule. *Am. Iron & Steel Inst.* v. *EPA,* 526 F.2d 1027, 1058, 1061, 1064 (3d Cir. 1975); *Weyerhaeuser Co.* v. *Costle,* 590 F.2d at 1054 n.70; *Reynolds Metals Co.* v. *EPA,* 760 F.2d at 562; *California & Hawaiian Sugar Co.* v. *EPA,* 553 F.2d at 287. In the 2015 rule record, EPA found that the pollutants of concern in CRL are the same pollutants that are present in, and in many cases are also pollutants of concern for, FGD wastewater, FA transport wastewater, BA transport water, and other CCR solids. This finding led the Agency to select chemical precipitation as the technology basis for the 2015 rule's NSPS and PSNS for CRL, based on technology transfer from the use of chemical precipitation on FGD wastewater.[94] This finding was never challenged. The EPA is basing the final rule CRL limitations on the same zero-discharge systems selected as BAT for treating FGD wastewater in this final rule. In contrast to comments that pollutants found in CRL are fundamentally different than those found in FGD wastewater, the EPA confirms its findings from the 2015 rule that CRL is characteristically like FGD wastewater. Even after accounting for additional data from 12 landfills gathered prior to the 2023 proposal, the EPA's analysis in the *CRL Analytical Data Evaluation—2024 Final Rule* (DCN SE11715) memorandum shows that CRL continues to have the same pollutants of concern in similar concentrations as other wastewaters, including FGD wastewater. Zero-discharge systems are available to treat this type of wastewater, and the limitations based on this technology would eliminate all arsenic, mercury, and other toxic pollutants from CRL discharges by the steam electric power generating industry. Moreover, just as the use of each individual technology within the BAT technology basis for FGD wastewater discussed in section VII.B.1 of this preamble supports the availability of each individual technology as BAT for that wastestream, based on technology transfer from FGD wastewater, the use of each individual technology is sufficient on its own to support the availability of a zero-discharge limitation for CRL.

At proposal, the EPA solicited comment on zero discharge limitations for CRL as well as transferring the 2015 NSPS or 2020 VIP nonzero numeric limitations for FGD wastewater. Some commenters claimed the need to discharge from a zero-discharge system after retirement. While EPA is requiring zero discharge of pollutants from CRL during active operations, this is based, in part, on the ability of active EGUs to use clean permeate or distillate resulting from CRL treatment either in an FGD absorber or as boiler makeup water. After the last EGU at a facility retires, it may become necessary for a facility to discharge the permeate or distillate from its zero-discharge treatment system. Thus, the EPA is transferring the BAT limitations from the 2020 VIP and 2015 NSPS to provide more flexibility to a plant post-retirement. Plants may discharge CRL permeate after retirement subject to the 2020 rule VIP limitations designed for permeate from a membrane filtration system. Alternatively, plants may discharge CRL distillate after retirement subject to the 2015 rule NSPS limitations designed for distillate from a thermal treatment system.[95]

Economic achievability of zero-discharge systems. The EPA finds that the costs of zero-discharge systems for control of CRL discharges are economically achievable. For further discussion of the economic analysis, see sections VII.F and VIII, below.

Non-water quality environmental impacts of zero-discharge systems. The EPA finds that the non-water quality environmental impacts associated with zero-discharge systems to control CRL discharges are acceptable. See discussion below in section VII.G and section X of this preamble.

b. The EPA rejects less stringent technologies than zero-discharge systems as BAT for CRL.

Except for the new subcategories for permanent cessation of coal combustion by 2034 and discharges of unmanaged CRL, discussed in sections VII.C.4 and VII.C.5 of this preamble, EPA is not selecting less stringent technologies than the zero-discharge systems discussed above. BAT is the ''gold standard'' for controlling water pollution from existing sources, and the Supreme Court has explained that BAT must achieve ''reasonable further progress'' toward the CWA's goal of eliminating pollution. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1003, 1006 (citing *Nat'l Crushed Stone* v. *EPA,* 449 U.S. at 75). The record shows that zero-discharge systems are available, are economically achievable, and have acceptable non-water quality environmental impacts. Therefore, with the exception of the new subcategory for permanent cessation of coal combustion by 2034, the EPA is not leaving BAT for determination on a case-by-case BPJ basis by the permitting authority. Similarly, except for the new subcategory for discharges of

[91] ERG. 2020. *Final Notes from Site Call with Duke Energy's Mayo Steam Station.* June 15 (DCN SE08964).

[92] The EPA notes that, while the utility employing this system filed comments on the proposed rule, it did not dispute in its comments that its system effectively operates zero discharge for CRL, nor did it dispute that zero discharge is technologically available for CRL.

[93] An additional three membrane filtration technology vendors successfully treat non-CCR landfill leachate, but the operators of these installations have so far chosen to discharge the clean permeate instead of operating with zero discharge.

[94] In establishing chemical precipitation as the basis for NSPS, the Agency stated that for combustion residual leachate, chemical precipitation is a well-demonstrated technology for removing metals and other pollutants from a variety of industrial wastewaters, including leachate from landfills not located at power plants. Chemical precipitation is also well demonstrated at steam electric power plants for treatment of FGD wastewater that contains the pollutants in combustion residual leachate (80 FR 67859).

[95] SDEs and thermal systems that do not generate a distillate would not require this flexibility.

unmanaged CRL, the EPA is not identifying as BAT the less stringent technology of chemical precipitation, as this technology would remove fewer pollutants than the BAT basis in this final rule, which the EPA has found is available, is achievable, and has acceptable non-water quality environmental impacts. Finally, the EPA is also rejecting the less stringent technologies of surface impoundments and chemical precipitation followed by a low hydraulic residence time biological treatment, as these systems would also remove fewer pollutants than the BAT basis in this final rule, which the EPA has found meets the requisite statutory requirements.

c. The EPA selects zero-discharge systems as NSPS for CRL.

At proposal, the EPA solicited comments on the propriety of revising NSPS for CRL based on decisions made with respect to BAT for CRL.[96] The EPA did not receive any comments on its solicitation for updating NSPS for CRL. After considering all of the technologies described in this preamble and TDD section 7, and in light of the factors specified in CWA section 306, the EPA concludes that zero-discharge systems represent BADCT for CRL at steam electric power plants, and the final rule promulgates NSPS based on these systems. More specifically, the BADCT technology basis for CRL is membrane filtration systems, SDEs, and thermal evaporation systems alone, or in any combination, including any necessary pretreatment (*e.g.,* chemical precipitation) or post-treatment (*e.g.,* crystallization).[97] Furthermore, where a permeate or distillate is generated from the final stage of treatment, the technology basis is a process wherein this water would then be recycled back into the plant as either FGD makeup water or EGU makeup water.[98] The record indicates that the zero-discharge systems that serve as the basis for the final NSPS are well demonstrated. This is fully supported by the discussion of the availability of zero-discharge systems for identifying BAT, both as a whole and as stand-alone technologies, as described above in section VII.B.3 of this preamble. As discussed in the preceding BAT discussion, because CRL is expected to continue to be generated and discharged even after the retirement of the plant, the EPA is also using the BAT technology basis identified to establish nonzero numeric limitations following a plant's eventual retirement—limitations based on membrane filtration for CRL permeate and limitations based on thermal evaporation for CRL distillate.

The NSPS in the final rule poses no barrier to entry. This is due, first, to the fact that no new coal-fired power plants are expected to be built. As the EPA's *Power Sector Trends Technical Support Document* states:

> It is unlikely that new conventional coal-fired EGUs will come online in the US. The last year in which a new coal-fired EGU (greater than 25 MW) was completed was in 2014. There are no new announced plans to build new coal-fired EGUs.[99]

This is consistent with EIA data [100] and is due to the uncompetitive financial realities of coal-fired power. Existing coal is almost universally estimated to be more expensive than replacement capacity moving forward.[101] Since no new coal-fired power plants are expected, updating NSPS to the same zero-discharge systems as BAT is more of a safeguard to ensure a consistent regulation of CRL, even if it likely will never apply.

Second, the final NSPS poses no barrier to entry based on the EPA's assessment of the possible impacts of the final NSPS on new sources using a comparison of the incremental costs of the final rule to the costs of hypothetical new generating units. The EPA developed NSPS compliance costs for new sources using a methodology similar to the one used to develop compliance costs for existing sources. The EPA's estimates for compliance costs for new sources are based on the net difference in costs between (1) wastewater treatment system technologies that would likely have been implemented at new sources under the previously established regulatory requirements and (2) those that would likely be implemented under the final rule. The EPA estimated that the incremental compliance costs for a new generating unit (capital and O&M) represent about one percent of the annualized cost of building and operating a new 650 MW coal-fired plant,[102] with capital costs representing approximately one percent of the overnight construction costs, and annual O&M costs also representing one percent of the fuel and other O&M cost of operating a new plant.

Finally, the EPA analyzed the non-water quality environmental impacts and energy requirements associated with the final BAT limitations for CRL. Since there is nothing inherently different between an existing and new source, the EPA drew on the analyses for existing sources and determined that NSPS based on the final rule BAT technologies have acceptable non-water quality environmental impacts and energy requirements. For further discussion of the non-water quality environmental impacts evaluated for BAT, see sections VII.G and X.

The EPA did not retain chemical precipitation as the basis for NSPS for CRL because, under CWA section 306, NSPS reflect ''the greatest degree of effluent reduction . . . achievable.'' Zero-discharge systems are capable of eliminating all discharges associated with CRL, and they form the BAT technology basis used to establish limitations for existing sources of CRL discharges in this rule. Moreover, establishing NSPS for CRL based on zero-discharge systems does not add to the overall estimated cost of the rule because the EPA does not predict any new coal-fired generating units will be installed in the timeframe of the EPA's analyses.

4. Legacy Wastewater

Except for the subcategory for legacy wastewater discharged from surface impoundments commencing closure after July 8, 2024, the EPA is reserving BAT basis for legacy wastewater at this time and instead is continuing to reserve BAT limitations for case-by case determination by the permitting authority, using its BPJ. This potential case-by-case outcome was explicitly

[96] The EPA did not solicit comment on revising any other NSPS because the proposed BAT technology bases for FGD wastewater and BA transport water would be similar to the 2015 BADCT technology bases for these wastestreams. The final rule is consistent with the proposal in that way.

[97] While three main technologies are listed here and are used to evaluate costs and non-water quality environmental impacts, the list is not meant to exclude use of FA fixation, direct encapsulation, evaporation ponds, or other zero-discharge treatment options where a facility uses these technologies to meet the zero-discharge standard established in this rule.

[98] The 2020 rule finalized a carve out from the definition of FGD wastewater applicable to ''treated FGD wastewater permeate or distillate used as boiler makeup water.'' The EPA is making the equivalent change to the definition of CRL for the same reasons the change was made to the definition FGD wastewater and to support consistency across these two zero-discharge wastewater streams. *See* 85 FR 64675.

[99] Available online at: *https://www.epa.gov/system/files/documents/2023-05/Power%20Sector%20Trends%20TSD.pdf.*

[100] Available online at: *https://www.eia.gov/todayinenergy/detail.php?id=54559#.*

[101] Energy Innovation Policy & Technology LLC®. 2023. *Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment.* January. Available online at: *https://energyinnovation.org/wp-content/uploads/2023/01/Coal-Cost-Crossover-3.0.pdf.*

[102] Energy Information Administration. 2024. *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies,* January 2024. Available online at *https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.*

identified by the Fifth Circuit Court of Appeals as an alternative the EPA should have considered in the 2015 rule. *Southwestern Elec. Power Company* v. *EPA,* 920 F.3d at 1021 (''[E]ven assuming a lack of data prevented the EPA from determining BAT for legacy wastewater, nothing required the agency simply to set impoundments as BAT. Instead, the EPA could have declined to set nationwide effluent guidelines for legacy wastewater and allowed BAT determinations to be made by each facility's permitting authority through the NPDES permitting process on a site-specific basis.'') (citations omitted).

In the 2015 rulemaking and subsequent litigation, petitioners argued that the EPA lacks authority to establish differentiated limitations for legacy wastewater, as compared to newly generated wastewater, because the text of the CWA does not contain specific distinctions based on when wastewater is produced. As explained in the 2015 rule and in briefs before the Fifth Circuit Court of Appeals, however, nothing in the statute requires the EPA to establish the same technology basis for each wastestream within a point source category when establishing limitations.[103] The CWA directs the EPA to take into account a variety of factors in establishing the best available technology economically achievable, including,'' ''process changes,'' ''non-water quality environmental impacts,'' and ''such other factors ats the Administrator deems appropriate.'' 33 U.S.C. 1314(b)(2)(B). As discussed further below, the rule's differentiated BAT limitations for legacy wastewater are based on the changes happening at plants under the CCR regulations in relation specifically to legacy wastewater, which by and large is contained in surface impoundments. The EPA's conclusion that it is appropriate to set different BAT limits for legacy wastewater based on the different way this wastewater is handled in response to the CCR regulations is within the Agency's broad discretion under the statute. *See Texas Oil & Gas Ass'n* v. *EPA,* 161 F.3d 923, 934 (5th Cir. 1998) (''EPA has significant discretion in deciding how much weight to accord each statutory factor under the CWA.'').

In contrast to the environmental group petitioners' arguments discussed above that legacy wastewater should be subject to the same limitations and standards as newly generated wastewater, some commenters on the 2023 proposed rule argued that the EPA lacks authority to establish BAT limitations on legacy wastewater *at all* since it was previously generated and ''treated'' under the prior ELGs. The CWA regulates discharges of pollutants, 33 U.S.C. 1311(a), and nothing in the CWA prohibits the EPA from applying discharge limitations to previously generated (and even ''treated'') wastewater. The Commenters' view would lead to results under the statute that Congress could not have intended. Under commenters' reading, if wastewater was treated to meet BPT regulations, it could not be treated any further to meet more stringent BAT regulations. This would be contrary to the CWA's technology-forcing scheme. In this case, the treatment referred to by the commenter is treatment using a surface impoundment. The Fifth Circuit has strongly suggested that, in light of the EPA's 2015 finding that surface impoundments are ''largely ineffective'' at removing dissolved metals, to achieve the BAT standard, something more than limitations based on surface impoundments should be required of legacy wastewater discharges. *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1015, 1017.

While commenters claim that it is not fair for plants to be subject to new limitations for wastewater generated when the plant was making operational decisions under a prior ELG, as further discussed below, the EPA finds that it is economically achievable for certain plants to meet additional limitations on their legacy wastewater, as required for Best Available Technology Economically Achievable under the CWA. Moreover, the EPA has considered the unique situation in which some plants may have already closed and, therefore, lack an active revenue stream to pay for additional pollution controls. For the case-by-case legacy wastewater limitations discussed below, permitting authorities can consider the site-specific economic achievability of particular requirements when identifying BAT. For the legacy wastewater subcategory described in section VII.C.6 of this preamble, the BAT limitations are based on chemical precipitation. The EPA rejected more stringent limitations than those based on chemical precipitation, alone, in part because of the higher costs of more advanced treatment-based limitations, given that many legacy discharges may occur after a plant ceases operating.

The EPA also disagrees with commenters that plants could not have known they might be subject to more stringent limits for wastewater already generated. The CWA has always regulated discharges, and plants should have known that their discharges would potentially be subject to more stringent requirements, given that the CWA envisions progressively more stringent limits to meet progressively more stringent standards. *See Texas Oil & Gass Ass'n* v. *EPA,* 161 F.3d at 927; *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1006–07. Plants should have known that the limitations to which their discharges are subject might changes, as ELGs are established or revised, including to account for technological advancements. *See* CWA sections 301(d) and 304(b), 33 U.S.C. 1311(d) and 1314(b). Indeed, water quality concerns might require water quality-based effluent limitations that change over time as well.

In the first subsection immediately below, the EPA discusses its rationale for reserving BAT limitations to be derived on a BPJ-basis to control legacy wastewater. In the second subsection, EPA discusses why it is not selecting surface impoundments as BAT for legacy wastewater. In the final subsection, the EPA discusses why it is not selecting more stringent technologies as BAT for legacy wastewater, except for a subcategory of legacy wastewater discussed in section VII.C.6 of this preamble. For further discussion of the subcategory for legacy wastewater discharged from surface impoundments commencing closure after July 8, 2024, see section VII.C.6 of this preamble.

a. BPJ-based BAT Limitations Will Continue To Apply to Legacy Wastewater

The EPA is finalizing the approach proposed for this rule for legacy wastewater: permitting authorities will continue to develop BAT limitations on a case-by-case basis, using their BPJ. The EPA received comments supporting and opposed to the case-by-case approach. Commenters opposing this approach came from two perspectives. Some industry commenters believed that only BPT and water quality-based effluent limitations currently apply to legacy wastewater and that the EPA should finalize this approach. In contrast, other commenters viewed the proposed BPJ approach as impermissibly allowing permitting authorities to select surface impoundments as BAT. In the alternative, these commenters recommended that the EPA formally constrain the permitting authorities' discretion when determining BAT with a BPJ analysis. Commenters that supported the EPA's proposed approach

[103] This was a question the Fifth Circuit never reached because it vacated and remanded the 2015 legacy wastewater limitations on other grounds. *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1015.

opposed selecting more stringent technologies as BAT in large part because of the timelines for completing closure under the CCR regulations. Some commenters also stated that most or all legacy wastewater will have been discharged prior to the effective date of any final rule. Finally, commenters from multiple perspectives universally opposed certain definitional changes that the EPA solicited comment on at proposal, involving establishment of two new classes of legacy wastewaters called surface impoundment decant wastewater and surface impoundment dewatering wastewater. Their comments opposed the changes because of the unclear delineation between the two types of legacy wastewater and the view that all legacy wastewater should be regulated the same.

After considering the comments received and evaluating the record in light of the factors specified in CWA section 304(b)(2)(B), the EPA finds that no single technology is technologically available and economically achievable for control of pollutants in legacy wastewater, except for legacy wastewater from a subcategory of EGUs as discussed in section VII.C.6 of this preamble. Because of process changes happening at plants in the form of ongoing and soon-to-be-completed surface impoundment closures under the CCR regulations, the EPA finds that it is infeasible to finalize a nationwide BAT limitation for legacy wastewater mid-closure. The statute requires BAT to reflect what is technologically available, is economically achievable, and has acceptable non-water quality environmental impacts based on consideration of several factors, including ''process changes,'' ''non-water quality environmental impacts,'' and ''such other factors'' as the Administrator deems appropriate. Because many facilities with surface impoundments are in the process of closing their surface impoundments under the CCR regulations (regulations that create safeguards around the disposal of solid waste, as explained in section IV.E of this preamble), the technology that represents BAT for legacy wastewater treatment is likely to vary from site to site depending on several factors. These factors include, but are not limited to, the types of wastes and wastewaters present, the characteristics of the legacy wastewater in each layer of a surface impoundment, the amount of legacy wastewater remaining to be treated in a surface impoundment, the treatment already available on site, the treatment option costs, the extent to which CWA requirements could interfere with closure timeframes required under the CCR regulations, the potential for increased groundwater contamination, and the potential for increased discharges through groundwater that are determined to be the functional equivalent of direct discharges (FEDDs) to a WOTUS.

The effect of the EPA declining to identify a nationally applicable BAT for this wastewater is that permitting authorities will continue to establish site-specific technology-based effluent limitations using their BPJ.[104] Because the limitations under this rule are required to be derived on a site-specific basis, taking into account the requisite BAT statutory factors and applying them to the circumstances of a given plant, these case-by-case limitations would by definition be technologically available and economically achievable and have acceptable non-water quality environmental impacts, where the permitting record reflects that such is the case. While the dynamic and changing nature of this wastestream at this time means there is no typical site, given the CCR regulations' closure requirements, the EPA agrees with commenters that, were permitting authorities to choose surface impoundments as the BAT technology for a particular site using the same rationale that the EPA put forth in 2015, this would run afoul of the Fifth Circuit's decision that found selecting surface impoundments as BAT was arbitrary, capricious, and inconsistent with the ''technology-forcing mandate of the CWA.'' *Southwestern Elec. Power Company* v. *EPA,* 920 F.3d at 1017.

Factors the permitting authority must consider when establishing BPJ-based BAT effluent limitations for legacy wastewater are specified in section 304(b) of the CWA, 33 U.S.C. 1314(b), and 40 CFR 125.3(d). The EPA solicited comment on whether it should explicitly promulgate, in regulatory text, specific elements related to these factors for this steam electric wastewater. While some commenters advocated for further restrictions to deter or even prohibit permitting authorities from selecting surface impoundments as BAT through a BPJ analysis, the CWA and EPA regulations already require the permitting authority to evaluate whether more stringent technologies are available, are economically achievable, and have acceptable non-water quality environmental impacts. Moreover, given existing case law and information known about more advanced technologies, the EPA believes that a permitting authority which chooses to select surface impoundments as BAT would face substantial legal risk unless it could justify its decision based on the BAT statutory factors. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1018 n.20 (''EPA may have been uncertain about what the precise BAT for legacy wastewater should be, but the record fails to explain why impoundments are BAT, if that term is to have any meaning.'').

The EPA agrees with commenters that differentiating legacy wastewaters into two distinct classes in the manner the EPA solicited comment on at proposal (*i.e.,* decant and dewatering wastewaters) is unnecessary and not useful; therefore, the EPA is not finalizing new definitions to distinguish classes of legacy wastewater. The proposal would have potentially doubled the number of BPJ analyses performed by permitting authorities—as there would have been two classes of legacy wastewater that each required BPJ determinations—without likely changing the ultimate outcome of treatment of the legacy wastewater as a whole. Moreover, it is doubtful that creating two new definitions of legacy would be useful given that, where a surface impoundment is already closing under the CCR regulations, both types of wastewater would likely be discharged before a new CWA permit incorporating the limitations in this final rule would take effect. Lastly, given the confusion commenters expressed over how to interpret the definitions, the EPA is concerned that finalizing these definitions would complicate implementation.

The EPA also agrees with commenters that the vast majority of legacy wastewater likely has been, or will be, discharged pursuant to BPJ determinations under existing permits. Rapid closure of many of these surface impoundments is ongoing under the CCR regulations. The EPA notes that most surface impoundments had to cease receipt of waste by April 11, 2021, and commenced closure soon after. These surface impoundments were either unlined, in violation of location restrictions, or both. The EPA estimates that 398 of 507 such surface impoundments are less than 40 acres and thus must close within seven years of commencing closure (five years plus

[104] Because some commenters took issue with the EPA's statements in the proposed rule that, under the prior regulations in effect, BAT limitations based on a permitting authority's BPJ are appropriate for legacy wastewater, the Agency is explicitly reserving BAT limitations for legacy wastewaters in the regulatory provisions setting forth BAT requirements for FGD wastewater, BA transport water, FA transport water, and flue gas mercury control wastewater to avoid any ambiguity regarding whether BPJ applies.

a possible two-year extension).[105] The remaining 109 are over 40 acres and thus can receive additional two-year extensions. Even with the possibility of extensions, dewatering is one of the first steps of closure and, therefore, most of the 507 surface impoundments which have already begun the closure process will have completed dewatering before permitting authorities issue NPDES permits implementing this final ELG rule.

Moreover, as is the case for all promulgated effluent limitations guidelines, the requirements for direct dischargers [106] in this rule do not become applicable to a given discharger until they are contained in revised NPDES permits. NPDES permits are typically issued for the maximum allowed five-year permit term. Most permits are not immediately revised after the EPA issues a new ELG rule, rather permitting authorities incorporate the new ELG rule limitations at the time the next five-year permit is up for reissuance. In addition, it is not uncommon for permits to be administratively continued beyond the five-year permit term if a permittee submits a timely permit renewal application, in which case the existing permit stays in effect until a new permit is effective. *See* 40 CFR 122.6. Thus, even if these new ELG requirements were implemented into NPDES permits in a timely manner following their effective date on July 8, 2024, the vast majority of legacy wastewater would have been discharged or will be discharged pursuant to BPJ determinations in existing permits rather than pursuant to any regulations the EPA might promulgate. Much, if not all, of the remaining legacy wastewater is included in the 19 surface impoundments expected to be covered by the subcategory for legacy wastewater discharged from surface impoundments commencing closure after July 8, 2024. This subcategory is further described in section VII.C.6 of this preamble.

Reserving BAT limitations for this legacy wastewater to be developed by the permitting authority on a BPJ-basis would allow permitting authorities, on a case-by-case basis, to impose more stringent limitations (including potentially zero-discharge limitations) based on technologies that remove more pollutants than the previously promulgated BPT limitations based on surface impoundments, depending on what is technologically available and economically achievable for individual facilities. In this way, the final rule does not ''freeze impoundments in place as BAT for legacy wastewater,'' a criticism of the 2015 rule's legacy wastewater limitations by the Fifth Circuit, which acknowledged that BAT has in inbuilt 'reasonable further progress' standard and that 'BPT serves as the prior standard with respect to BAT.' *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1017 (citation omitted). Moreover, this final rule record includes information about technologies beyond surface impoundments and their application to legacy wastewater that could be useful to permitting authorities in making their determinations.

b. The EPA rejects surface impoundments as BAT for legacy wastewater.

The EPA is not selecting surface impoundments as the BAT basis for controlling discharges of legacy wastewater because there are more effective technologies for controlling discharges that some plants could use. Several plants described in the record employ technologies ranging from chemical precipitation to zero-discharge systems for legacy wastewaters. The previously promulgated BPT limitations are based on surface impoundments. As the Fifth Circuit has acknowledged, BPT is merely the first step toward the CWA's pollution reduction goals and provides the ''prior standard'' against which the stricter BAT is to be measured. *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1006 (citing *Nat'l Crushed Stone,* 449 U.S. at 69, 77 & n.14). Therefore, the EPA is retaining the current case-by-case BAT approach rather than selecting surface impoundments.

c. The EPA rejects specific, across-the-board technologies more stringent than surface impoundments as BAT for legacy wastewater.

The EPA is not selecting more stringent, one-size-fits-all technologies, such as chemical precipitation, biological treatment, membrane filtration, thermal evaporation, and/or spray dryer evaporation as the BAT basis for controlling discharges of legacy wastewater, except for the legacy wastewater described in section VII.C.6 of this preamble. As explained previously, many plants with legacy wastewater have already begun closure of their surface impoundments under the CCR regulations. These plants are in different stages of the dewatering process, as they are trying to meet their closure deadlines under the CCR regulations. Requiring limitations based on a more stringent BAT technology basis at all plants that are in the process of dewatering when their permit is renewed but before closure is complete would jeopardize their ability to meet their closure deadlines under the CCR regulations. This is because having to consider and add one or more treatment components would slow the dewatering process, at some plants more than others. If plants could not meet their closure deadlines under the CCR regulations, this would be an unacceptable non-water quality environmental impact.

Furthermore, some zero-discharge technologies are not available to plants after they cease coal combustion, even if the discharge of legacy wastewater will occur after that date. For example, while Boswell Energy Center has installed and is operating an SDE for treating several wastewaters including legacy wastewater, this SDE would not be available to a facility that no longer produces power because it is designed and operated using a slipstream of the hot flue gas to evaporate the wastewater, a heat source no longer available after retirement.

Although the EPA cannot determine that a particular technology is available within the meaning of CWA section 304(b) to treat the legacy wastewater described in this section, the Agency could expect the permitting authority to select more stringent technologies than surface impoundments on a site-specific basis. In some cases, the stage of closure and realities on site may point to use of a more stringent technology. For example, a facility in early closure stages may be able to lease commercial, off-the-shelf equipment to treat its legacy wastewater. Alternatively, permitting authorities could assess the technologies a plant already uses for treatment of other wastewaters and determine that the legacy wastewater could be readily directed to an existing treatment system.

5. Definitional Changes

The EPA is finalizing two definitional changes. The first definitional change applies to high intensity, infrequent storm events as described in subsection (a), below. The second definitional change applies to decommissioning wastewater from FGD wastewater treatment equipment and ash handling equipment as discussed in subsection (b), below.

a. Definitional Change for High-Intensity, Infrequent Storm Events

The EPA is finalizing a definitional change for all the wastewaters for which the Agency is establishing zero-

[105] *See* 40 CFR 257.102(f).

[106] Indirect dischargers (those who discharge to POTWs) are subject to pretreatment standards that are directly implemented and enforceable. *See* CWA section 307, 33 U.S.C. 1317; 40 CFR part 403.

discharge limitations in this final rule: FGD wastewater, BA transport water, and CRL. Specifically, the EPA is excluding from the definitions of these wastewaters any discharges which are necessary (*i.e.,* cannot be managed with existing systems or practices) as the result of high-intensity, infrequent storm events exceeding a 10-year storm event of 24-hour or longer duration (*e.g.,* a 10-year, 30-day storm event). The EPA is specifically selecting this duration storm event as this is a consistent duration storm event to the storm event described in 40 CFR part 423 with respect to regulation of coal pile runoff.[107] Due to these definitional exclusions, such discharges would not be subject to the zero-discharge requirements that otherwise apply to FGD wastewater, BA transport water, and CRL under this final rule. Instead, these discharges would be considered a ''low volume waste source'' and the TSS and oil and grease BPT limitations for such waste would apply, as well as any BAT limitations for the low volume waste source developed by a permitting authority using its BPJ. As discussed in section XIV.C.4 of this preamble, the EPA is also finalizing reporting and recordkeeping requirements that facilities must comply with when they discharge during these high intensity, infrequent storm events, which are intended to demonstrate that the discharge is necessary and to provide information about the time, place, and volume of the necessary discharge. Each of the wastestreams subject to this definitional change is discussed in turn below.

At the outset, the EPA notes that stormwater is not FGD wastewater, BA transport water, or CRL, though it may mix with these wastewaters. Instead, the EPA describes stormwater on its website as follows:

> Stormwater runoff is generated from rain and snowmelt events that flow over land or impervious surfaces, such as paved streets, parking lots, and building rooftops, and does not soak into the ground. The runoff picks up pollutants like trash, chemicals, oils, and dirt/sediment that can harm our rivers, streams, lakes, and coastal waters. To protect these resources, communities, construction companies, industries, and others, use stormwater controls, known as best management practices (BMPs). These BMPs filter out pollutants and/or prevent pollution by controlling it at its source.[108]

Since stormwater picks up different pollutants, for example dirt, it has inherently different characteristics from the wastewaters regulated in this final rule. Furthermore, larger storm events result in a higher fraction of stormwater and stormwater pollutants as compared to the pollutants in FGD wastewater, BA transport water, and CRL. Taken together, this means that during these high intensity, infrequent storm events, a requirement to treat to zero discharge would essentially be requiring higher and higher amounts of stormwater treatment, rather than treatment of the pollutants of concern in these three wastewaters.

Based on the CWA statutory factors of ''process employed,'' ''engineering aspects'' of control techniques, and non-water quality environmental impacts, the EPA concludes that a zero-discharge requirement for discharges of CRL, FGD wastewater, and BA transport water that cannot be managed with existing systems or practices during a high-intensity, infrequent storm event is not warranted. The CWA statutory factor of ''cost'' provides additional support for EPA's decision. Regarding CRL, the EPA solicited comment on the potential to exclude discharges from the definition of CRL to account for specific storm events. Several commenters expressed concerns that CRL collection systems in general, or at specific facilities, collected both CRL and stormwater. In such cases, segregation of the CRL and stormwater may not be possible for treatment. One specific design of concern to these commenters, although not the only problematic one, employs a chimney system to channel stormwater vertically through a landfill in order to minimize contact with the ash, and thus minimize the generation of CRL in the first place. In some cases, this design is used voluntarily as a BMP to reduce the potential for groundwater contamination; in other cases, commenters pointed out that such a design is required by state law. The EPA agrees that minimizing the formation of CRL promotes the goals of both RCRA and the CWA by reducing the pollutants mobilized into CRL that can potentially migrate into groundwater, be discharged into surface water, or both. It would be impracticable (and in some cases may also violate state law) for a facility with such a landfill design to rip out these chimney structures in order to segregate CRL from stormwater, but more importantly it would result in the mobilization of more pollutants into CRL (because more water would percolate through the CCR), not less.

Alternatively, it may be possible to design larger treatment systems that can handle even the additional flows resulting from the high intensity, infrequent storm events specified in the definitional change described above. However, here too the record does not support zero-discharge systems as BAT to control necessary discharges of CRL during the storm events described. First, the rainfall that reached the collection system via the chimneys would either be pristine rainfall or rainfall contaminated by runoff sediment, and thus would not be CRL. Second, CRL generated by the rainfall that does percolate through the landfill would not reach the leachate collection system at the same time as the rainfall that passes immediately through the chimneys. Depending on the infiltration rate and depth of the CCR, it may take hours, days, weeks, or longer for the additional CRL generated by the rainfall to ultimately pass through the layers of CCR and into the leachate collection system below. Until the leachate from the storm event migrates to the leachate collection system, the treatment system could be treating mostly or entirely non-CRL stormwater.

The EPA concludes that the considerations discussed above are sufficient to support its decision to exclude necessary discharges of CRL during high intensity, infrequent storm events from the definition of CRL and, thus, from the zero-discharge requirement that would otherwise apply to CRL. The EPA also notes that cost is a statutory factor that it must consider when establishing BAT, and that treatment of the higher flows comprised of primarily non-CRL during such high intensity, infrequent storm events would be more costly. EPA examined the data in the National Oceanic and Atmospheric Administration's *Precipitation Frequency Data Server*.[109] The amount of precipitation for a storm event in the 10-year to 25-year storm event range will be approximately double that of a 1-year storm event. It approximately doubles yet again for something even more extreme such as a 1,000-year storm event. Thus, were the EPA not to finalize a definitional change related to high-intensity, infrequent storm events, a facility would be forced to construct a system at least double the size, but potentially much larger, in order to manage volumes from these low-probability of occurrence

[107] 40 CFR 423.12(b)(10) (BPT limitations) and 423.15(a)(12) and (b)(12) (NSPS) provide, ''Any untreated overflow from facilities designed, constructed, and operated to treat the volume of coal pile runoff which is associated with a 10, year, 24 hour rainfall event shall not be subject to'' the TSS limitations or standards that otherwise apply to discharges of coal pile runoff.

[108] Available online at: *https://www.epa.gov/npdes/npdes-stormwater-program.*

[109] Available online at: *https://hdsc.nws.noaa.gov/pfds/.*

precipitation events. As a result, costs could at least double.[110] The doubling of costs to have a system available to manage volumes from these low-probability events occurring once every 25 or 200 years would be a wholly disproportionate *costs per day in use* when compared to the costs actually considered in the EPA's cost estimates, costs that already treat the average annual flows of CRL under the more common storm events to zero discharge approximately nine years and 364 days out of every 10 years.[111] The EPA views the high cost of treating CRL discharges that cannot be managed by an existing zero-discharge system or practices during a high intensity, infrequent storm event as an additional factor supporting the EPA's decision to exclude such discharges from the definition of CRL.

The definitional change discussed for CRL is also appropriate for FGD wastewater. The EPA solicited comment on a zero-discharge requirement for discharges of FGD wastewater, including the availability of zero-discharge systems and ability of plants to meet zero-discharge limitations. The EPA received one comment suggesting that a zero-discharge requirement for FGD wastewater could force an offline plant to operate its coal-fired boilers for the sole purpose of recycling the excess water generated in its FGD treatment system during a storm event. The EPA acknowledges that some FGD treatment systems include open-air tanks and a few include lined surface impoundment pretreatment to increase physical settling. In these scenarios, it is possible that stormwater will increase the need to recycle the clean permeate or distillate from a zero-discharge system at a time when the plant is offline.[112] This scenario does raise concerns that there might be limited instances in which a discharge is necessary or otherwise might result in a plant running when it is not needed. This could result in unnecessary air emissions, a non-water quality environmental impact that the EPA is required to consider.

The EPA also notes that several facilities already co-treat FGD wastewater and CRL.[113] Nothing in this final rule would prohibit facilities from achieving zero discharge of these two wastewaters with a single system. Therefore, the EPA expects that, where there are economies of scale, facilities may elect to co-treat these wastewaters. While nothing in the final rule would prohibit such co-treatment, not finalizing a stormwater flexibility for FGD wastewater where such flexibility exists for CRL, and a discharge is necessary for the co-treated CRL, could make such co-treatment impracticable. Furthermore, just as with CRL, discharges during high intensity, infrequent storm events would consist primarily of rainfall and runoff rather than of FGD wastewater. For the reasons above, the EPA finds that zero-discharge systems are not BAT for discharges of FGD wastewater that cannot be managed with existing systems or practices during these high intensity, infrequent storm events.

Finally, the definitional change discussed above for CRL and FGD wastewater is appropriate for BA transport water as well. The EPA solicited comment on the potential need for purges from a closed-loop BA handling system, including purges related to precipitation events, which were a basis for including a purge allowance in the 2020 rule. The EPA's record shows that remote MDS systems can install roofing to mitigate the need to discharge during storm events, and this feature is included in the Agency's cost estimate. One commenter provided information about the necessary cooling received from its open air remote MDS and suggested that it may need to install expensive heat exchangers to make up for the lost cooling once a roof is installed. The EPA agrees that cooling BA (a waste so hot that is sometimes generated in molten form) is one of the primary functions of a BA handling system. While this comment did not provide data showing that cooling would fall enough to jeopardize the ability to recycle wastewater, to the extent that roofing could affect the ability of a remote MDS to return water cool enough to quench BA,[114] the EPA would agree that this could jeopardize the ability of that system to attain zero discharge during high intensity, infrequent storm events.

The EPA also acknowledges that some BA handling systems must recycle some BA into their FGD wastewater treatment systems either by design or to manage the volume of water or chemistry of water in the closed-loop system. For the reasons stated above finding that a definitional change is warranted for FGD wastewater, it would also make sense to have a definitional change for BA transport water, especially to the extent that the BA transport water in closed-loop systems is used as FGD makeup water to comply with the zero discharge-requirements. For the reasons above, the EPA finds that zero-discharge systems are not BAT for BA transport water discharges that cannot be managed with existing systems or practices during high intensity, infrequent storm events.

While the previous considerations are sufficient to support the Agency's decision to exclude necessary discharges of BA transport water during high intensity, infrequent storm events from the definition of BA transport water and, thus, from the zero-discharge requirement that would otherwise apply to BA transport water, the EPA notes that the statutory factor of cost also supports the EPA's decision. Remote MDS systems are not the only systems that the EPA estimates will operate as closed-loop systems. At some facilities, larger settling systems such as concrete basins have already been constructed. In contrast to MDS systems, the EPA acknowledges that its cost estimates assume that some non-MDS wet systems (*e.g.,* dewatering bins, lined surface impoundments, basins) would make low-cost changes to recirculate BA transport water rather than install a new BA handing system. A roof or other cover over surface impoundments or basins that could be acres in size would be cost prohibitive at such sites.

In summary, after considering public comments and the facts and analyses in the record, and in light of the requirements for the EPA to consider several statutory factors (including the process employed at the facility, the engineering aspects of the application of various types of control techniques, and

[110] Volume is one of the primary inputs to the EPA's cost models of zero-discharge systems. The relationships are not linear, but costs do increase at a similar enough rate for purposes of the illustrative argument above. For more information on the specific cost estimates the EPA used, see section 5 of the TDD.

[111] Furthermore, doubling the costs of these systems would not be justified as the CRL, and thus the pollutants in CRL, would not reach the leachate collection system until much later. Instead, this larger system would be underutilized for years or decades at a time, only to treat a wastestream composed of mostly non-CRL wastewater on the infrequent occasion that it was ultimately called upon just for the sake of saying that the system eliminated all CRL discharges. Courts have recognized that while CWA section 301 is intended to help achieve the national goal of eliminating the discharge of all pollutants, at some point the technology-based approach has its limitations. *See Am. Petroleum Inst.* v. *EPA,* 787 F.2d 965, 972 (5th Cir. 1986) (''EPA would disserve its mandate were it to tilt at windmills by imposing BAT limitations which removed de minimis amounts of polluting agents from our nation's waters . . . .'').

[112] Recall that recycling of the permeate or distillate into the FGD system or the boiler is part of the zero-discharge system technology basis.

[113] Other commenters that do not yet have co-treatment also suggested that co-treatment be allowed.

[114] The commenter stated that its facility needed water below 140 degrees Fahrenheit in order to sufficiently cool its BA.

non-water quality environmental impacts) the EPA rejects zero-discharge systems as BAT to control necessary discharges of FGD wastewater, BA transport water and CRL mixed with stormwater during high intensity, infrequent storm events exceeding a 10-year storm event of 24-hour or longer duration (*e.g.,* a 30-day storm event). The EPA's decision is further supported after considering the associated costs. While the EPA is excluding necessary discharges resulting from such storm events from the definitions of CRL, FGD wastewater, and BA transport water, this does not mean that no limitations apply to these discharges. As low volume waste sources (which are defined in 40 CFR part 423 as wastewater from all sources except those for which specific limitations or standards are otherwise established in this part), these discharges are subject to the BPT limitations for low volume waste sources as well as any BAT limitations developed by the permitting authority on a BPJ basis.

Furthermore, the EPA notes that facilities would still be required to follow any stormwater requirements. High-intensity, infrequent storm events are currently addressed in the *2021 Multi-Sector General Permit* (MSGP), the most recent to address industrial stormwater, including stormwater at steam electric power plants.[115] The MSGP requires a Stormwater Pollution Prevention Plan (SPPP), which is developed at each individual facility and is therefore tailored to the types and frequencies of storms experienced at each facility. This makes sense as a site prone to hurricanes may take different stormwater precautions than a site located in an arid climate.[116] As a result of site-specific permit requirements or voluntary efforts, some steam electric facilities already exceed the performance of a 10-year, 24-hour design standard and would have even less frequent stormwater-related discharge needs than envisioned by the definitional change in this final rule. For example, in a recent BA transport water purge request for the Four Corners Power Plant, the utility demonstrated the ability to fully recycle under a 10-year storm event, and only showed the need for discharge during a 100-year storm event.

For the final rule, in addition to requiring facilities to meet limitations applicable to low volume waste sources, to ensure facilities are not backing away from more protective management practices, the EPA is requiring that any necessary discharges of CRL, FGD wastewater, or BA transport water resulting from such a high-intensity, infrequent storm event be accompanied by an official certification statement that includes information that these discharges were necessary (*i.e.,* could not be managed with existing systems or practices). Importantly, nothing in this definitional change or the associated reporting and recordkeeping requirement changes a facility's obligations for stormwater management under its current permit or general permit. For further discussion of this reporting and recordkeeping requirement, see section XIV.C.4 of this preamble.

b. Definitional Change for Decommissioning Wastewater

When the EPA finalized non-zero limitations for FGD wastewater and BA transport water in the 2020 rule, facilities could discharge these wastewaters when decommissioning equipment after retirement. The EPA proposed zero-discharge limitations and at proposal did not specifically address the scenario in which plants may be decommissioning their zero-discharge treatment equipment. One commenter said that wastewater must be discharged from such equipment at the time of decommissioning and recommended that the Agency either retain the 2020 rule purge allowance or finalize an end-of-life flexibility that the EPA proposed in 2019 for ''wastewater present in equipment when a facility is retired from service.'' Another commenter, in the context of the permanent cessation of coal combustion subcategory, suggested that the Agency allow facilities to discharge wastewaters for 120 days after permanently ceasing coal combustion.

The EPA agrees with the commenter that, given the zero-discharge limitations being finalized for FGD wastewater and BA transport water in this rule, an end-of-life flexibility for certain discharges is warranted. More specifically, the EPA finds a limited definitional change, appliable to all EGUs, to allow one-time discharges associated with decommissioning an FGD wastewater treatment system or BA handling system after retirement is appropriate. Part of the basis for the zero-discharge limitations in this rule is tied to the ability of an active plant to recycle the wastewaters back into the plant (*e.g.,* as FGD makeup water). This is no longer the case when a facility retires. Furthermore, as discussed in the subsequent sections VII.C.3 and VII.C.4, the Agency is finalizing a tiered set of zero-discharge limitations for FGD wastewater and BA transport water at EGUs permanently ceasing coal combustion, but it is including time that allows for discharges of these wastewaters up to 120 days after the EGU ceases coal combustion, due to the technical constraints of achieving zero-discharge when active operations have ceased. Because there is no material difference in residual discharges from a decommissioned system at a plant retiring before the December 31, 2028, or December 31, 2034, dates in the permanent cessation of coal combustion subcategories, as compared to a plant retiring after those dates, it is consistent to treat facilities retiring before and after those dates the same. Thus, the EPA is excluding wastewater removed from wastewater treatment or ash handling equipment within the first 120 days of decommissioning the equipment from the definitions of FGD wastewater and transport water.

While the EPA is excluding this narrow class of wastewaters from the definitions of FGD wastewater and transport water, this does not mean that no limitations apply to discharges of such wastewater. As low volume waste sources (which are defined as wastewater from all sources except those for which specific limitations or standards are otherwise established in part 423), these discharges are subject to the BPT limitations for low volume waste sources, as well as any BAT limitations developed by the permitting authority on a BPJ basis. The EPA expects permitting authorities to consider any treatment technologies available at the plant in devising appropriate, case-by-case BAT limitations.

6. Clarification on the Interpretation of 40 CFR 423.10 (Applicability)

The EPA clarified at proposal that part 423 applies to discharges of legacy wastewater at inactive/retired power plants because the discharge of these wastewaters ''result[s] from the operation of a generating unit.'' [117] This

[115] Available online at: *https://www.epa.gov/npdes/stormwater-discharges-industrial-activities-epas-2021-msgp.*

[116] While climate change may be driving more extreme storm events in some areas, it is possible that, given this design and the age of the facility, the facility will never experience a situation where a stormwater-related discharge under this rule would be required before its retirement from service.

[117] 40 CFR 423.10. The provisions of the part apply to discharges resulting from the operation of a generating unit by an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel (coal, oil,

Continued

interpretation is consistent with the EPA's longstanding view on the applicability of 40 CFR part 423 to inactive/retired plants, as well as with implementation by state permitting authorities. For example, in 2016, the South Carolina Department of Health and Environmental Control reissued a permit to the South Carolina Electricity & Gas Company's Canadys Station Site (SC0002020) which stated, ''Because electricity is not being generated, 40 CFR part 423-Steam Electric Power Generating Point-Source Category will only apply to the discharge of legacy wastewaters.'' [118] This is also consistent with the EPA's position provided in response to comments on the 2015 rule, in which the Agency stated:

> EPA disagrees with the commenter that the 'effluent limits would not apply' to discharges associated with retired units. For example, combustion residual leachate from landfills or surface impoundments containing combustion residuals from the time a generating unit was operating may occur and continue to be subject to the effluent limitations and standards requirements long after a generating unit is retired. Similarly, if an impoundment containing wastewater created while the generating unit was in operation (*e.g.,* FGD wastewater, fly ash or bottom ash transport water) were to discharge, it would certainly be discharging wastewater 'resulting from the operation of a generating unit.' In these instances, even though the generating unit may no longer be in operation, the wastewater is the result of its previous operation. Therefore, to the extent that steam electric power plants discharge wastestreams like this resulting from the operation of a generating unit, the ELGs do apply.[119]

Due to the proposed expansion of the RCRA CCR closure requirements to inactive surface impoundments at inactive (*i.e.,* retired) plants, some of these surface impoundments are expected to dewater and therefore discharge legacy wastewater. At proposal, the EPA sought to clarify the applicability of part 423 to these legacy wastewaters since the Agency was soliciting comment on establishing nationally applicable BAT limitations rather than reserving BAT limitations to be developed on a case-by-case basis using a permitting authority's BPJ. As described in section VII.B.4 of this preamble, the EPA is instead declining to establish a nationwide BAT for discharges of legacy wastewaters, except for those discharges of legacy wastewater described in section VII.C.6 of this preamble (which would not occur at previously retired facilities), and it is thus continuing to reserve these BAT limitations for case-by-case decision-making using the permitting authorities' BPJ. As a result, the applicability of part 423 to legacy wastewater discharges at inactive/retired plants would not impact the technology-based effluent limitations that apply to such discharges. In other words, the EPA's interpretation makes no difference to the ultimate disposition of legacy wastewater because, while the EPA interprets the rule to apply to legacy wastewater at inactive/retired steam electric power plants, the same BPJ approach called for in this rule would apply even if inactive/retired plants were not subject to part 423, given that BAT limitations must be developed on a BPJ basis where nationally applicable limitations do not apply. *See* CWA section 402(a)(1), 33 U.S.C. 1342(a)(1); 40 CFR 122.44, 125.3. For further discussion of these additional legacy surface impoundments, *see Legacy Wastewater at CCR Surface Impoundments—Estimated Volumes, Treatment Costs, and Pollutant Loadings* (DCN SE11503).

At proposal, the EPA also solicited comment on whether there are other wastewaters that may continue to be discharged after the retirement of a facility and the generation of electricity is the ''but for'' cause of the discharge. Some commenters suggested that the Agency should clarify its interpretation to include additional wastewaters such as CRL, while others disagreed that this would be a permissible reading of the regulation. Commenters opposed to an expansive reading stated that other wastewaters such as CRL generated after closure were not generated as a result of operating a generating unit, but as the result of precipitation percolating through a waste management unit. Commenters opposed to an expansive reading also pointed to the history of 40 CFR part 423, suggesting that the EPA never intended to cover CRL from retired power plants as it never evaluated these facilities.

The EPA agrees with commenters stating that discharges of CRL, even after retirement, result from the operation of a steam EGU. Were it not for operation of the unit, there could be no CRL discharges, regardless of whether there are other conditions that also exist to facilitate the discharge. Moreover, the EPA disagrees with commenters that the Agency never intended to cover CRL from retired power plants. As can be seen from the response to comment excerpt above, in 2015, the EPA expected that CRL discharges would continue to be subject to 40 CFR part 423 after a facility retired. This is an important clarification that makes it clear that the limitations being finalized, including those for subcategories, would continue to apply after the facility retires. At the same time, two other statements from the 2015 rule record demonstrate that the Agency only intended the regulations to cover leachate prospectively from the 2015 rule. First, also in the 2015 response to comments is the EPA's statement that:

> Retired landfills with or without leachate collection systems are not subject to the combustion residual leachate limitations and standards. EPA's methodology does not include costs or pollutant loadings removals from closed or retired landfills in its analyses.[120]

Second, in the 2015 TDD, the EPA stated that ''combustion residual leachate from retired units is not regulated in the final rule.'' These two statements, together with the earlier response to comments discussed above, reflect the actual approach finalized in the 2015 rule; namely, that only CRL generated and discharged at EGUs operating after the effective date of the 2015 rule was covered.[121] The approach taken in this final rule is consistent with that of the 2015 rule. That is, discharges of CRL (including unmanaged CRL) are covered prospectively by the final rule, but they will continue to be covered even after that facility and any waste management units generating CRL have retired. To the extent that a retired facility or closed waste management unit (WMU) is subject to 40 CFR part 423 but its discharges of CRL (including unmanaged CRL) are not subject to this rule, permitting authorities will instead continue to establish technology-based effluent limitations that reflect BAT using their BPJ. Thus, these facilities will have to meet BAT limitations for their discharges of CRL that are available, are economically achievable,

or gas), fuel derived from fossil fuel (*e.g.,* petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium. This part applies to discharges associated with both the combustion turbine and steam turbine portions of a combined cycle generating unit.

[118] DHEC (Department of Health and Environmental Control). 2016. *FACT SHEET AND PERMIT RATIONALE: South Carolina Electric & Gas Company, Canadys Station Site.* NPDES Permit No. SC0002020. May 16.

[119] U.S. EPA (Environmental Protection Agency). 2015. *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments.* September (SE05958A2) Page 3–563.

[120] U.S. EPA (Environmental Protection Agency). 2015. *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments.* September (DCN SE05958A6) Page 7–82.

[121] This is the case even though the Fifth Circuit Court of Appeals vacated and remanded the BAT limitations for CRL finalized in 2015.

and have acceptable non-water quality environmental impacts.[122]

C. Subcategories

The EPA has authority in a national rulemaking to establish different limitations for different plants after considering the statutory factors listed in CWA section 304(b). *See Texas Oil & Gas Ass'n* v. *EPA,* 161 F.3d at 938 (stating that the CWA does not ''exclude a rule allowing less than perfect uniformity within a category or subcategory.'').

In the 2015 rule, the EPA established subcategories for small EGUs (less than or equal to 50 MW nameplate capacity) and oil-fired EGUs. In this rulemaking, the EPA did not propose to revise or eliminate these subcategories and did not receive any comments on removing such subcategories; therefore, this final rule keeps the 2015 subcategories intact.

In the 2020 rule, the EPA established additional subcategories for high FGD flow facilities (EGUs with FGD purge flows of greater than 4 million gallons per day), LUEGUs (EGUs with a capacity utilization rating of less than 10 percent per year), and EGUs permanently ceasing coal combustion by 2028. For these subcategorized units, the EPA established different limitations using different technology bases as compared to the limitations applicable to the rest of the steam electric point source category. In 2023, the EPA proposed to eliminate the 2020 rule's high FGD flow subcategory and LUEGU subcategory, but also proposed to retain the permanent cessation of coal combustion by 2028 subcategory.

Based on public comment, in this final rule, the EPA is eliminating the 2020 rule's high FGD flow subcategory, as well as the LUEGU subcategory, but is retaining the permanent cessation of coal combustion by 2028 subcategory. These three subcategories are addressed in subsections 1–3 below.

In addition, the final rule creates three new subcategories based on the proposal, as described further in subsections 4–6 below. These subcategories are for (1) EGUs permanently ceasing coal combustion by 2034, (2) discharges of unmanaged CRL, and (3) discharges of legacy wastewater from surface impoundments that will commence closure under the CCR regulations after the effective date of this final rule. For these subcategorized units, the EPA is establishing different limitations (using different technology bases) than the ones applicable to the rest of the steam electric point source category.

1. Plants With High FGD Flows

Except as discussed in section VII.C.4 of this preamble, as proposed, the EPA is eliminating the high FGD flow subcategory promulgated in the 2020 rule. The EPA finds that, after evaluating public comments, along with the record and factors specified in CWA section 304(b)(2)(B), the subcategory is no longer warranted.

At the time of the 2020 rule, the EPA's understanding was that this subcategory would apply to only one facility, TVA Cumberland, which operated with FGD purge flows of over 400 million gallons per day. The EPA based the creation of the subcategory on the supposedly disparately high costs that would result from high FGD flows at this facility and thus the need to install a larger, more costly treatment system than at other EGUs.

Several commenters on the 2019 and 2023 proposals claimed that this subcategory of one facility was inconsistent with the CWA, and further argued that the costs estimated for TVA were overestimated and not disparately high as compared to other facilities.[123] The EPA acknowledges that its cost estimates were higher than TVA's own estimates for installing biological treatment, and thus costs may not be as disparately high as indicated in the 2020 rule.

Since the 2020 rule, TVA has announced a notice in the **Federal Register** of plans to retire the facility, which are further detailed in a draft Environmental Impact Statement (EIS). *See* 86 FR 25933 (May 11, 2021). This draft EIS solicits comment on three alternatives, all of which include retirement but with different electricity replacement scenarios. While TVA's comments on the 2023 proposed rule still appear to support retaining this subcategory, its comments also confirm that TVA plans to retire the Cumberland plant.

Due to TVA's retirement plans, the EPA finds that this subcategory is no longer warranted based on the rationale provided in the 2020 rule. As appears in its **Federal Register** document, all the alternatives TVA is considering (including its preferred alternative) would result in the plant's retirement. To the extent that the plant is able to participate in the permanent cessation of coal combustion by 2028 subcategory, the plant's limitations would be based on surface impoundments.[124] To the extent that the plant operates beyond 2028, it would be able to participate in the permanent cessation of coal combustion by 2034 subcategory (discussed below in section VII.C.4 of this preamble) and have limitations based on chemical precipitation (the same 2020 rule limitations applicable to plants in the high FGD flow subcategory). Thus, there would be no costs to TVA Cumberland associated with the more stringent, zero-discharge limitations in this final rule, and thus no disparate costs. Disparate costs were the sole rationale for the high FGD flow subcategory, and neither the EPA nor commenters have identified alternative bases that could serve to support this subcategory. Furthermore, after the retirement of TVA Cumberland, because this plant was the only one qualifying as a high flow facility, this subcategory becomes a null set; therefore, the EPA is eliminating the subcategory.

2. LUEGUs

Except as discussed in section VII.C.4 of this preamble for the new permanent cessation of coal combustion subcategory, as proposed, the EPA is eliminating the LUEGU subcategory after evaluating public comments received and the record as it informs the factors specified in CWA section 304(b)(2)(B). The EPA finds that the subcategory is no longer warranted. The EPA established the subcategory for LUEGUs in the 2020 rule based on cost (disparate capital costs), non-water quality environmental impacts (energy reliability), and other factors the Administrator deemed appropriate (*i.e.,* harmonization with CAA and RCRA regulations that apply to electric utilities).

The EPA received comments on the proposal both in support of and opposition to eliminating this subcategory. Commenters supporting elimination of the subcategory agreed with the statements and findings included in the EPA's proposal that the

[122] The EPA conservatively included closed WMUs in its cost analyses when they were located at active facilities. CRL flows at composite-lined landfills could be comingled with the flows from adjacent, active landfill cells. Furthermore, unmanaged CRL flows could be caught up in site-wide pump-and-treat operations where both active and closed WMUs are present. Thus, while this is a conservative assumption, it is a reasonable estimate that helps ensure the costs of the rule are not underestimated and are economically achievable.

[123] The EPA notes that these commenters were also petitioners in the consolidated *Appalachian Voices* case discussed in section IV of this preamble.

[124] TVA submitted a NOPP for the permanent cessation of coal combustion subcategory to the Tennessee Department of Environment and Conservation on October 6, 2021. To date, the EPA is not aware of any actions taken at the facility to meet the limitations in the high flow subcategory no later than December 31, 2023, as required to participate in this subcategory.

2020 LUEGU subcategory is no longer warranted based on the factors originally cited. Commenters opposed to elimination of this subcategory faulted the EPA for several reasons. First, they contended that the EPA could not evaluate the subcategory without better understanding how many plants intend to make use of it. In particular, they claimed that the EPA's understanding of the universe of plants intending to make use of the subcategory is not based on a comprehensive accounting of NOPPs and facilities with LUEGU limitations included via the transfer provisions of the 2020 rule, contained in § 423.13(o), which allow facilities to transfer into the LUEGU subcategory automatically without requesting a permit modification. Second, these commenters reiterated the findings in the 2020 rule and claimed they supported creation of the subcategory. Finally, the commenters disputed the proposal's characterization of GSP Merrimack Station, the only plant currently seeking to participate in this subcategory.

Under the 2020 rule, a facility wishing to avail itself of the limitations available in the subcategories for low utilization or permanent cessation of coal combustion, or any facility wishing to participate in the VIP, was required to file a NOPP by October 13, 2021. The EPA acknowledges that facilities and permitting authorities were not required to provide NOPPs to the EPA as part of the 2020 rule. Instead, the EPA obtained NOPP submissions through normal permit reviews, as courtesy copies, in providing technical support to state permitting authorities, and via the sharing of a set of NOPPs that environmental groups had already collected. In total, these NOPPs cover 94 EGUs at 38 plants—about 34 percent of all facilities predicted to incur costs under the 2020 rule.[125] Furthermore, the EPA did not receive comments from any facilities stating that they had filed NOPPs of which the EPA was not aware. Most of these NOPPs are from plants wishing to avail themselves of flexibilities in the 2020 rule other than the LUEGU subcategory. Only one facility indicated it would like to avail itself of the BAT limitations in the subcategory for LUEGUs: the GSP Merrimack Station in Bow, New Hampshire.

On March 27, 2024, GSP issued a press release announcing a settlement with the EPA whereby GSP has committed to permanently ceasing coal combustion at Merrimack Station no later than June 1, 2028. This dates is memorialized in a Settlement Agreement that arose out of an Alternative Dispute Resolution process conducted in connection with an administrative appeal of an NPDES permit modification for Schiller Station.[126] As a result of the only known facility with LUEGUs retiring and no comments revealing the existence of any other LUEGU, the EPA is eliminating the LUEGU subcategory in this final rule, except to the extent it supports entry into the new permanent cessation of coal by 2034 subcategory discussed below.

3. EGUs Permanently Ceasing Coal Combustion by 2028

The EPA is retaining the subcategory for EGUs permanently ceasing coal combustion by 2028 after evaluating public comments and the record in light of the factors specified in CWA section 304(b)(2)(B) and finding that the subcategory continues to be warranted. For EGUs in this subcategory, the EPA is also retaining the 2020 rule BAT limitations based on surface impoundments.

The EPA proposed to retain the subcategory for EGUs permanently ceasing coal combustion by 2028 and simultaneously extended the NOPP filing date through a companion direct final rulemaking. *See* 88 FR 18440 (March 20, 2023). No commenter argued for the elimination of this subcategory, though commenters disagreed about any potential changes. Some commenters suggested extending the latest date to permanently cease coal combustion beyond December 31, 2028, while other commenters opposed any extension of this date. Similarly, some commenters sought additional transparency and enforceability of the criteria to permanently cease coal combustion while other commenters opposed such modifications. In the subsections below, the EPA discusses why this subcategory continues to be warranted and why it is retaining the BAT technology bases for this subcategory. The EPA also discusses the zero-discharge limitations that apply after ceasing coal combustion, as well as reporting and recordkeeping requirements in the final rule.

a. The subcategory continues to be warranted based on several statutory factors.

The EPA established this subcategory in the 2020 rule based on the statutory factors of cost, the age of the equipment and plants involved, non-water quality environmental impacts (including energy requirements), and such other factors as the Administrator deems appropriate (harmonization with the CCR regulations' alternative closure provisions). The EPA notes the unanimous agreement that this subcategory should be retained, and it agrees with commenters, although the EPA is no longer relying on cost as a primary basis for this subcategory, as discussed below.

In particular, the EPA recognizes that, based on the creation of this subcategory, which was part of the 2020 rule, many plants have begun moving forward with plans to retire or repower in the then-eight-year time frame afforded under that rule. In the 2020 rule, EPA described how recent NERC reliability assessments showed one region that was not anticipated to meet its reference margin [127] and another region that was anticipated to be very close to its reference margin (and these assessments are consistent with NERC's *2023 Long-Term Reliability Assessment*). Therefore, for the 2020 rule, the EPA found that premature closure of some plants and/or EGUs as a result of the general, industry-wide limitations would be an unacceptable non-water quality environmental impact because it could impact reliability. Utilities with a limited remaining useful life have planned and budgeted for replacement capacity under timelines approved by public utility commissions (PUCs) and public service commissions (PSCs) as part of the normal integrated resource planning process. These submissions were made since the 2020 rule, as part of the 2020 rule's eight-year window to permanently cease coal combustion. The EPA does not think that it should disrupt these ongoing plans by changing the date halfway through the period that plants have moved forward with those plans. Maintaining the same timeframe allowed by the prior rule supports efforts planned for the orderly transition of generating capacity as a result of the 2020 rule in a way that helps ensure

[125] Four units at two plants are represented twice. NOPPs for two units were initially filed by one plant for the VIP, and NOPPs for two separate units were initially filed by another plant for the LUEGU subcategory. Both plants then filed new NOPPs for their two units to permanently cease coal combustion by 2028.

[126] *See, e.g., https://indepthnh.org/2024/03/27/last-coal-plants-in-new-england-to-voluntarily-close-transitioning-to-renewable-energy-parks/.*

[127] ''Reference margins, which differ by region, are reserve margin targets based on each area's load, generation capacity, and transmission characteristics. In some cases, the reference margin level is a requirement implemented by states, provinces, independent system operators, or other regulatory bodies. Reliability entities in each region aim to have their anticipated reserve margins surpass their reference margins, which are generally set near 15% in most regions.'' Available online at: *https://www.eia.gov/todayinenergy/detail.php?id=31492.*

grid reliability and weighs in favor of retaining the same date in this rule.

With respect to air pollution, a non-water quality environmental impact, the EPA notes that several utilities have decided to make use of this subcategory where they may not have previously had plans to retire by 2028. For example, the DTE Energy Company filed a NOPP for this subcategory for its Belle River Power Plant and is now planning to retire in 2028 rather than 2030. Replacing coal-fired capacity with natural gas, renewables, and other sources leads to decreased emissions of several air pollutants. The subcategory allows utilities seeking to retire by 2028 to do so and achieve the associated air pollution and solid waste reductions, which further supports the finding that the subcategory continues to be warranted.

In addition, the EPA still wishes to harmonize this rule with the CCR alternative closure provisions as described in the proposal, and those provisions have not changed. Twenty-five plants are seeking to use the alternative closure provisions under the CCR regulations, which allow for closure of the unlined impoundment(s) and the power plant no later than 2023 (for surface impoundments under 40 acres) or 2028 (surface impoundments over 40 acres).[128] Elimination of the permanent cessation of coal combustion subcategory from this ELG could interfere with the plans of utilities with surface impoundments in the 2028 category, complicating their compliance with the CCR regulations. Furthermore, the EPA has also finalized additional flexibility under the Good Neighbor Plan, discussed in section IV.E.2.a of this preamble.[129] Harmonization between regulations on air, water, and land pollution gives industry certainty to plan and implement these requirements in an orderly, efficient manner.

Although the EPA concludes that the previous factors are sufficient to justify the retention of this subcategory, the EPA also notes that, with respect to cost, the 2020 rule record included an analysis showing that amortization of capital costs for less than the typical 20-year life of pollution control equipment leads to greater annualized costs per MWh as compared to costs at EGUs that are not retiring or repowering. Many plants made decisions at the time of the 2020 rule to opt for the alternative retirement compliance pathway, and they are now several years into meeting the milestones for that path. In this case, a change in the rule requiring these facilities to install new treatment technologies would result in even shorter timeframes and even greater costs per MWh. Thus, the EPA finds that cost provides an additional basis for the subcategory.

After considering all the information above, the EPA finds that the record and statutory factors discussed above continue to support this 2020 subcategory and associated limitations. Each of these bases, discussed above and supported by a statutory factor, provide a separate and independent basis for subcategorization, save for the cost basis which serves as additional support. Thus, the EPA is retaining this subcategory in its current form. This includes retaining the BAT technology basis for limitations applicable to EGUs in this subcategory, surface impoundments. Surface impoundments are technologically available, are economically achievable, and have acceptable non-water quality environmental impacts as applied to this subcategory. They represent BAT for this subcategory because they support the ability of plants with a limited remaining useful life to continue with their ongoing plans for orderly retirement or repowering. The EPA also notes that they would not lead to higher costs for facilities based on the remaining useful life of their EGUs. The EPA did not select any other technology for this subcategory because it would disrupt plants' already approved, ongoing plans for ceasing coal combustion by 2028. The EPA also notes that imposing more stringent BAT limitations on EGUs in this subcategory would subject them to greater costs per MWh, as compared to EGUs in the general industry, given that these EGUs have a limited remaining useful life.

b. The final rule includes post-coal combustion cessation zero-discharge limitations for EGUs in this subcategory to avoid circumvention.

The EPA proposed to include zero-discharge limitations applicable after the permanent cessation of coal combustion date, December 31, 2028, for all discharges in this subcategory. The goal of these limitations was to ensure that a facility does not manipulate the flexibilities in 40 CFR part 423 to avoid meeting industry-wide zero-discharge limitations and then simply keep discharging without relevant permit limitations being applicable to them. The EPA received several comments on these limitations that would apply after the permanent cessation of coal combustion date. Some commenters expressed a preference for them and sought an even stronger requirement that the zero-discharge limitations be retroactive. Other commenters suggested that these limitations are not necessary, are unduly burdensome, and are not cost-free, even where a facility successfully permanently ceases coal combustion by the specified date. One commenter in the latter category suggested a 120-day flexibility for facilities that permanently ceased coal combustion to allow for some residual discharges of these wastewaters as necessary, subject to requirements no more stringent than BPT limitations.

After considering these comments, the EPA is finalizing zero-discharge limitations that would apply after the permanent cessation of coal combustion date, December 31, 2028, with modifications from the proposal, in order to ensure that the eligibility for participation in this subcategory designed for EGUs that permanently cease coal combustion is not circumvented. The modifications the EPA made to these limitations following proposal are based on legitimate concern raised in public comments concerning the potential need to discharge for a relatively short period of about fourth months following the permanent cessation of coal combustion. For example, a facility retiring on December 31, 2028, may still need to discharge the wastewater remaining in existing tanks from the final hours and days of lawful operations. The EPA does not wish to interfere with owner/operator plans for the permanent cessation of coal combustion or discourage the use of this subcategory by unfairly preventing any residual discharges that are necessary after coal combustion has permanently ceased.

The final rule reflects that the EPA continues to view zero-discharge limitations that apply following the permanent cessation of coal combustion date as an appropriate tool to avoid circumvention, as well as some flexibility to account for legitimate concern regarding the need to discharge following the permanent cessation of coal combustion date. The final rule thus contains a tiered set of zero-discharge limitations applicable following December 31, 2028:

[128] Further information is available online at: *https://www.epa.gov/coalash/coal-combustion-residuals-ccr-part-implementation.*

[129] To facilitate a potentially economic and environmentally superior unit-level compliance response across the programs that nonetheless maintains the NO_X reductions required by the state budgets from 2026 forward in the proposal, the EPA requested comment on potentially deferring the application of the backstop daily rate for large coal EGUs that submit written attestation to the EPA that they make an enforceable commitment to retire by no later than the end of calendar year 2028. 87 FR 20036, 20122 (April. 6, 2022).

• The first tier of these limitations is composed of zero-discharge limitations for FGD wastewater and BA transport water after April 30, 2029. These limitations would apply if the EGU had in fact permanently ceased coal combustion by December 31, 2028, as the plant represented it would. As suggested in the comments, this date is 120 days after the latest permanent cessation of coal combustion date, allowing for facilities to complete any necessary residual decommissioning discharges.[130]

• The second tier is composed of zero-discharge limitations for these same wastewaters after December 31, 2028. If a plant fails to cease combustion of coal by 2028, as it represented it would, for any reason other than those specified in section 423.18, these zero-discharge limitations would automatically apply.

Dischargers to which the second tier applies, the EPA notes, would be subject not only to this rule's requirements, but also to enforcement for false statements in their filings under § 423.19—for example, statements made in the NOPP, in the annual progress reports, in the notice of material delay, and for failure to file a notice of material delay in a timely fashion. Any reporting and recordkeeping violations would also be subject to enforcement. The EPA finds that, together, the zero-discharge limitations and reporting and recordkeeping requirements, as modified below, are sufficient to ensure that facilities do not unfairly benefit by continuing to discharge after the subcategory's permanent cessation of coal combustion date.

c. The final rule includes additional reporting and recordkeeping requirements for EGUs in this subcategory.

For a discussion of additional reporting and recordkeeping requirements, see section XIV.C.1 of this preamble.

4. EGUs Permanently Ceasing Coal Combustion by 2034

The EPA proposed a new ''early adopter'' subcategory for EGUs permanently ceasing coal combustion by December 31, 2032, with certain eligibility criteria targeted toward those plants that had already installed the FGD and BA technology bases on which the 2020 rule rested by the date of the 2023 proposed rule. The EPA solicited comment on whether the permanent cessation of coal combustion date should be earlier or later than 2032, as well as the propriety of the proposed criteria based on technology adoption for the subcategory. Based on public comments, the EPA is finalizing the new subcategory, except that the date for permanently ceasing coal combustion is December 31, 2034, rather than 2032. In addition, the EPA is not establishing strict eligibility criteria that would have narrowed the universe of plants to which this subcategory might apply. Through public comments, the EPA learned that, while many plants have continued to move toward compliance with the 2020 rule limitations, including by making various expenditures toward that goal (*e.g.,* securing contracts, conducting pilots, etc.), relatively few had actually installed the technologies on which the 2020 rule limitations were based by the time the 2023 proposed rule was published. In some cases, this was due to the timing of when a plant's NPDES permit was expected to be renewed. As a result, the cutoff that the EPA proposed—in terms of both the date for adoption and what steps constituted adoption—as well as other cutoffs that the EPA considered, would not necessarily capture the universe of plants that the EPA intended to capture. Moreover, the bases for this subcategory in terms of the statutory factors, as discussed further below, support this subcategory even without the proposed requirement for installation of the 2020 rule BAT technologies by the 2023 proposed rule date.

For EGUs that permanently cease coal combustion by December 31, 2034, the EPA is establishing limitations for FGD wastewater and BA transport water that are the same as those in place following the effective date of the 2020 rule. These limitations differed for some EGUs if they participated in a subcategory promulgated by the 2020 rule, but for the general industrial category consisted of limitations based on chemical precipitation followed by low residence time biological reduction treatment for FGD wastewater and limitations based on high recycle rate systems for BA transport water.

The final rule also covers discharges of CRL from EGUs in the new permanent cessation of coal combustion subcategory. The EPA notes that facilities discharge CRL either alone or in combination with FGD wastewater and BA transport water. The EPA solicited comment at proposal on the treatment of CRL at EGUs that will soon permanently cease coal combustion and close their CCR landfills. In response to this solicitation, several commenters recommended either including CRL in any new permanent cessation of coal combustion subcategory or creating a separate subcategory for CRL generated at landfills nearing closure. Several commenters recommended that CRL discharged from retired EGUs or EGUs that were about to retire should be subcategorized to avoid imposing disparate costs. One commenter pointed to the Agency's findings that the volume of CRL generated after closure of a landfill was approximately an order of magnitude lower than the volume of CRL generated during that landfill's operation.

The EPA agrees with many of these comments and is including CRL as one of the wastestreams covered by the new permanent cessation of coal combustion by 2034 subcategory. While an EGU is still combusting coal, that combustion generates CCR, which in turn generates CRL. As well as being tied to ongoing operations during a facility's remaining useful life (as are FGD wastewater and BA transport water), CRL can be comanaged with FGD wastewater (as is currently done at some facilities). Furthermore, including CRL in this subcategory promotes ease of administration, avoiding the creation of a separate subcategory for CRL designed to accomplish the same fundamental goals.

For CRL discharged at EGUs in this subcategory, the EPA is reserving BAT limitations to be developed on a BPJ basis by the permitting authority until the permanent cessation of coal combustion, after which the EPA is establishing mercury and arsenic limitations based on chemical precipitation, which are the same limitations that EPA proposed for all discharges of CRL.

The EPA received a number of comments on the overall propriety of the proposed subcategory. Though commenters were split, many supported a new subcategory for additional flexibility but disagreed with the contours of what the EPA proposed. After considering the comments and evaluating the record in light of the factors specified in CWA section 304(b)(2)(B), the EPA finds that a new permanent cessation of coal combustion subcategory is warranted. The statutory bases for this subcategory are discussed in the subsection below. The rationale for the selected BAT technology bases appears thereafter, as well as the rationale for rejecting other technologies. Importantly, this subcategory is in addition to the 2020 rule's permanent cessation of coal combustion by 2028 subcategory, which is carried forward in this rule. While the

[130] The EPA notes that these do not include discharges of legacy wastewaters from surface impoundments closing under the CCR rule, which are covered by different regulatory provisions.

two subcategories are similar in that they apply to EGUs that plan to permanently cease combustion of coal, they differ as discussed below.

a. This subcategory is justified based on several statutory factors.

This subcategory is supported by consideration of three CWA section 304(b) statutory factors: age of equipment and facilities involved, non-water quality environmental impacts, and cost. The EPA notes that the cost factor supports subcategorization, but it is not relying on that factor as a primary basis for the subcategory. Each of the bases discussed below and supported by a statutory factor provide a separate and independent basis for subcategorization, except for cost, which simply provides additional support.

Age of the equipment and facilities involved. The EPA recognizes that this 2024 rule establishes new, more stringent limitations over the limitations promulgated in 2020. For some plants, that means that they may no longer be able to rely on parts of the wastewater treatment systems they installed to meet the 2020 limitations to meet the new 2024 limitations. Under the Act's technology-forcing regime, imposing limitations requiring facilities to shift installation to new pollution control technologies is warranted as more effective technologies are available and economically achievable. In the particular circumstances here, however, the ''age of equipment and facilities involved'' supports allowing plants with EGUs permanently ceasing combustion of coal by December 31, 2034, to continue to meet limitations under the 2020 rule. Such facilities either have recently or are in the process of installing technologies to meet the 2020 rule limitations and, rather than require these facilities to also install technologies to meet limitations under the 2024 rule as well, given the short remaining useful life of certain plants, the EPA views it as reasonable to provide flexibility in this rule for plants with EGUs permanently ceasing combustion of coal by December 31, 2034.

There are many coal-fired EGUs that have announced a retirement or fuel conversion that would occur after December 31, 2028, which is the date used to establish the 2020 subcategory applicable to EGUs permanently ceasing coal combustion. In table VII–2 below, the EPA presents all of the announcements at EGUs estimated to potentially make new investments under this final ELG rule.

TABLE VII-2. Announced Coal-Fired EGU Retirements and Fuel Conversions

#	EIA ID	Plant Name	State	Unit #	Nameplate Capacity	Year Retire or Convert
1	6113	Gibson Generating Station	IN	3	627	2029
2	6113	Gibson Generating Station	IN	4	631	2029
3	298	Limestone Electrical Generating Station	TX	1	893	2029
4	298	Limestone Electrical Generating Station	TX	2	956.8	2029
5	1893	Boswell Energy Center	MN	3	364.5	2029
6	8219	Ray D Nixon	CO	1	207	2029
7	6761	Rawhide Energy Station	CO	1	293	2029
8	2712	Roxboro Steam Plant	NC	1	410.8	2029
9	2712	Roxboro Steam Plant	NC	2	657	2029
10	6021	Craig Station	CO	C3; 3	474.4	2030
11	55479	Wygen 1	WY	1	95	2030
12	6641	Independence Plant	AR	1	850	2030
13	6641	Independence Plant	AR	2	850	2030
14	470	Comanche Station	CO	3	856.8	2030
15	8066	Jim Bridger Power Plant	WY	3	577.9	2030
16	8066	Jim Bridger Power Plant	WY	4	584	2030
17	6068	Jeffrey Energy Center	KS	3	680.936	2030
18	7210	Cope	SC	ST1	432.9	2030
19	663	Deerhaven Generating Station	FL	2	250.7	2031
20	2442	Four Corners Steam Electric Station	NM	4	818.1	2031
21	2442	Four Corners Steam Electric Station	NM	5	818.1	2031
22	6165	Hunter Plant	UT	1	461	2031
23	3403	Gallatin	TN	1	300	2031
24	3403	Gallatin	TN	2	300	2031
25	3403	Gallatin	TN	3	327.6	2031
26	3403	Gallatin	TN	4	327.6	2031
27	6249	Winyah Generating Station	SC	1	315	2031
28	6249	Winyah Generating Station	SC	2	315	2031
29	6249	Winyah Generating Station	SC	3	315	2031
30	6249	Winyah Generating Station	SC	4	315	2031
31	8223	Springerville Generating Station	AZ	2	424.8	2032
32	8069	Huntington	UT	1	498	2032
33	8069	Huntington	UT	2	498	2032
34	3298	Williams Station	SC	ST1	586.4	2032
35	6177	Coronado Generating Station	AZ	U1B; CO1	456	2032
36	6177	Coronado Generating Station	AZ	U2B; CO2	456	2032
37	1241	LaCygne Generating Station	KS	1	893	2032
38	2727	Marshall Steam Station	NC	3	710	2032
39	2727	Marshall Steam Station	NC	4	710	2032
40	1733	Monroe Power Plant	MI	1	817.2	2032
41	1733	Monroe Power Plant	MI	2	822.6	2032

42	6165	Hunter Plant	UT	2	461	2032
43	6165	Hunter Plant	UT	3	490	2032
44	1379	Shawnee	KY	1	175	2033
45	1379	Shawnee	KY	2	175	2033
46	1379	Shawnee	KY	4	175	2033
47	1379	Shawnee	KY	5	175	2033
48	1379	Shawnee	KY	6	175	2033
49	1379	Shawnee	KY	7	175	2033
50	1379	Shawnee	KY	8	175	2033
51	1379	Shawnee	KY	9	175	2033
52	7790	Bonanza Power Plant	UT	1	500	2033
53	628	Crystal River Energy Complex	FL	4; ST4	739.3	2034
54	628	Crystal River Energy Complex	FL	5	739.3	2034
55	1040	Whitewater Valley	IN	1	33	2034
56	1040	Whitewater Valley	IN	2	60	2034
57	6090	Sherburne County Generating Plant	MN	3	1000	2034
58	2712	Roxboro Steam Plant	NC	3	745.2	2034
59	2712	Roxboro Steam Plant	NC	4	745.2	2034
60	6113	Gibson Generating Station	IN	1	635	2035
61	6113	Gibson Generating Station	IN	2	635	2035
62	2721	James E Rogers Energy Complex (f.k.a. Cliffside Steam Station)	NC	6	909.5	2035
63	703	Georgia Power Company - Plant Bowen	GA	3	952	2035
64	703	Georgia Power Company - Plant Bowen	GA	4	952	2035
65	6018	East Bend Station	KY	2	600	2035
66	1004	Edwardsport Generating Station	IN	CT1; CT2; ST	618	2035
67	8042	Belews Creek Steam Station	NC	1	1245	2035
68	8042	Belews Creek Steam Station	NC	2	1245	2035
69	56068	Elm Road Generating Station	WI	1	701.3	2035
70	56068	Elm Road Generating Station	WI	2	701.3	2035
71	1356	Ghent	KY	1	557	2037
72	1356	Ghent	KY	3	557	2037
73	1356	Ghent	KY	4	556	2037
74	6138	Flint Creek Power Plant	AR	1	558	2038
75	6065	Iatan Generating Station	MO	1	726	2039
76	1241	LaCygne Generating Station	KS	2	685	2039
77	4158	Dave Johnston Plant	WY	4	360	2039
78	6068	Jeffrey Energy Center	KS	1	680.936	2039
79	6068	Jeffrey Energy Center	KS	2	680.936	2039
80	6101	Wyodak Power Plant	WY	1	362	2039
81	2876	OVEC - Kyger Creek Station	OH	1	217.26	2040
82	2876	OVEC - Kyger Creek Station	OH	2	217.26	2040
83	2876	OVEC - Kyger Creek Station	OH	3	217.26	2040
84	2876	OVEC - Kyger Creek Station	OH	4	217.26	2040
85	2876	OVEC - Kyger Creek Station	OH	5	217.26	2040
86	3948	Mitchell Plant	WV	1	816.3	2040

87	3948	Mitchell Plant	WV	2	816.3	2040
88	6264	Mountaineer Plant	WV	1	1300	2040
89	983	Clifty Creek Station	IN	1	217.26	2040
90	983	Clifty Creek Station	IN	2	217.26	2040
91	983	Clifty Creek Station	IN	3	217.26	2040
92	983	Clifty Creek Station	IN	4	217.26	2040
93	983	Clifty Creek Station	IN	5	217.26	2040
94	983	Clifty Creek Station	IN	6	217.26	2040
95	3935	John E. Amos Plant	WV	1	816.3	2040
96	3935	John E. Amos Plant	WV	2	816.3	2040
97	3935	John E. Amos Plant	WV	3	1300	2040
98	6095	Sooner Power Plant	OK	1	569	2044
99	3470	W. A. Parish E.G.S.	TX	5	734.1	2045
100	3470	W. A. Parish E.G.S.	TX	6	734.1	2045
101	3470	W. A. Parish E.G.S.	TX	7	614.6	2045
102	3470	W. A. Parish E.G.S.	TX	8	614.6	2045
103	6095	Sooner Power Plant	OK	2	569	2045
104	963	Dallman	IL	4	230.1	2045
105	2952	Muskogee Generating Station	OK	6	572	2049
106	1167	Muscatine Power and Water Generating Station	IA	7	25	2052
107	1167	Muscatine Power and Water Generating Station	IA	8A; 8	93.05	2052
108	1167	Muscatine Power and Water Generating Station	IA	9	175.5	2052
109	2828	Cardinal	OH	1	615.2	2052
110	2828	Cardinal	OH	2	615.2	2052
111	1364	Mill Creek	KY	3	411	2052
112	1364	Mill Creek	KY	4	496	2052
113	2817	Leland Olds Station	ND	1	216	2052
114	2817	Leland Olds Station	ND	2	440	2052
115	645	Tampa Electric - Big Bend Station	FL	ST4	486	2052
116	136	Seminole Generating Station	FL	2	714.6	2052
117	3943	Fort Martin Power Station	WV	1	552	2052
118	3943	Fort Martin Power Station	WV	2	555	2052
119	6071	Trimble County	KY	1	566	2066
120	6071	Trimble County	KY	2	737.7	2066

* Entries 55 and 106 are EGUs less than 50 MW and therefore are not expected to be impacted by the rule

**While the EPA could not confirm the retirement of Shawnee 3 based on publicly available announcements at the time of analysis, during the 12866 review process, TVA confirmed that Shawnee 3 is also retiring in 2033. To the extent that the EPA has overestimated costs for Shawnee in its analysis, the analysis is conservative.

As seen in the table above, there have been 120 announcements that cover the years from 2029 to 2066. Of these, the EPA assumes that the nine EGUs retiring in 2029 would already be able to retire without making new investments under this rule, as these facilities could obtain a ''no later than'' date for the final limitations in this rule

from their permitting authority as late as December 31, 2029. In particular, the EPA notes that there is a cluster of announced retirements that tails off around 2034, with relatively few additional retirements in subsequent years until the 2039/2040 timeframe. These retirements have already been announced, planned for, and in some cases already approved by state and regional utility commissions or grid operators.

Some commenters expressed the view that the EPA had not considered reliance interests created by the 2020 rule and the EPA's decision to continue to implement that rule. The EPA disagrees. As discussed in previous sections, a facility cannot reasonably rely on the limitations established in a permit beyond the life of the permit itself, which is typically issued for five-year term, and the technology-forcing nature of the statute contemplates establishment and revision of limitations based on the best available technology reflecting currently available information. Nevertheless, as noted above, there are around 50 EGUs planning to permanently cease coal combustion between 2030 and 2034. The plants where these EGUs are located are in the process of installing or have recently installed new technologies under the 2020 rule, as the latest date for compliance in that rule is December 31, 2025. Without establishment of this subcategory, these plants could now be expected, under this rule, to potentially abandon parts of their 2020 treatment systems and install different treatment systems to comply with this 2024 rule, which has a compliance date of December 31, 2029, at the latest. These plants, in particular, have adopted certain strategies for an orderly transition to retirement or an alternate fuel source. The owners and operators of these plants have planned this transition taking into consideration effects on the broader grid and the reasonable useful life of recently installed or soon-to-be installed water pollution treatment equipment under the 2020 rule. Under these circumstances, the EPA does not view it as reasonable, in view of all the relevant considerations, to expect this group of plants to abandon prior installations under the 2020 rule and make additional upgrades under this 2024 rule, given the relatively short remaining useful life of the EGUs and treatment systems. The EPA notes, moreover, that plants installing and operating technologies to meet the 2020 limitations will achieve reductions of pollutants of concern in their wastewaters.

For CRL, it is also relevant to consider the remaining useful life of the WMU. As discussed earlier in this section, commenters recommended providing flexibility for landfills which were nearing retirement, as these landfills would be closed and generate a much smaller volume of CRL after retirement. Thus, instead of installing an oversized system to operate for potentially only a couple of years, a more tailored system could be installed to treat the smaller, post-closure flow.

Non-water quality environmental impacts (including energy requirements). The already planned retirements and fuel conversions of coal-fired EGUs discussed above would not only reduce or eliminate the water pollution associated with the continued operation of coal-fired EGUs, but it would also reduce or eliminate air pollution and solid waste generation. Electric utilities have an interest in continuing the planned, orderly transition of this cluster of EGUs in a way that achieves an adequate amortization period for the water pollution treatment technologies. Without subcategorization, this cluster of facilities may choose to extend the life of these EGUs in order to better amortize the costs of both the existing technologies as well as the new technologies that would otherwise be required by this final rule. If that were to happen, the reductions in air pollution and solid waste generation associated with the planned retirement or repowering of the EGU would be forgone, and the EPA finds these non-water quality environmental impacts weigh in favor of this subcategory.

In addition, ''energy requirements'' are an express non-water quality environmental impact that EPA must consider under the statute, and several commenters raised concerns regarding electric reliability. These commenters suggested that a subcategory was necessary to maintain reliability. As discussed above, the retirements of EGUs in this subcategory have already been announced, planned for, and in some cases already approved by state and regional utility commissions or grid operators. The Agency finds that the creation of this subcategory provides flexibility for the orderly retirement or fuel conversion of coal-fired EGUs in a way that helps ensure grid reliability, as it allows plants to continue as planned while meeting the 2020 limitations. This provides additional support for this subcategory.

Cost. The EPA also notes that ''cost' is a factor that EPA must consider under CWA section 304(b), and, while not a primary basis, this factor provides additional support for this subcategory. Looking at the EGUs permanently ceasing coal combustion by December 31, 2034, absent the new subcategory, these EGUs would have additional capital costs of $708M and additional O&M costs of $93.0M. Given the short remaining useful life of the EGUs and associated wastewater treatment equipment, facilities with these EGUs would have fewer years of remaining life over which to amortize these costs, and thus the costs would be higher per MWh than the costs per MWh for EGUs not permanently ceasing coal combustion by 2034. This is especially true of plants that might not install the 2024 technologies until the latest compliance date of December 31, 2029. The EPA analyzed these costs in the 2020 rule with respect to the permanent cessation of coal by 2028 subcategory and similarly found unreasonably higher costs for that subcategory.

Selection of 2034 date. While the EPA proposed a permanent cessation of coal combustion date of December 31, 2032, several commenters advocated for different dates as early as 2030 and as late as 2040. The record discussed above does not provide a clear delineation for where such a cutoff should be placed; however, after careful consideration of the information in the record, the EPA finds that selecting a permanent cessation of coal combustion date of December 31, 2034, to be a reasonable way to account for the interests described above while still furthering the CWA's goals. First, as discussed above, there is a cluster of retirements occurring from 2030 to 2034. Relatively few additional EGUs would qualify for the subcategory if the date were placed a year or two further into the future, but many EGUs would be excluded if the date were kept at 2032 or moved even earlier as some commenters suggested. Furthermore, cost per MWh becomes greater as the amortization period of new equipment is shortened. An effective date for the final rule in 2024 and a ''no later than'' date of December 31, 2029, means that plants with retirements or fuel conversions in the 2030 to 2034 cluster would amortize costs over a period of several months to at most, 10 years. Finally, the use of December 31, 2034, would create parity for facilities regardless of where they were in their permit cycle. Since the 5-year permit cycle after the effective date of this rule would go from 2024 to 2029, one more 5-year permit cycle after that ends in 2034.

Finally, the EPA has considered how the requirements in this rule interact

with the requirements in the CAA section 111 rule. One of the frequent comments received during the public comment period on the proposed ELG was that this rule and the CAA section 111 rule should be harmonized. Commenters argued that harmonization may consist of several aspects, including aligning compliance dates, aligning subcategories and other flexibilities, and aligning reporting and recordkeeping requirements. In the context of a subcategory for the permanent cessation of coal combustion, the EPA finds that the subcategory discussed here creates sufficient space for the flexibilities under the CAA section 111 rule to be utilized as appropriate.

As described in section IV.E.2 of this preamble, the final CAA section 111 rule consists of only two coal-fired EGU subcategories, and no longer has subcategories for EGUs retiring by 2032 or 2034 as were in the proposed CAA section 111 rule. Instead, the final CAA section 111 rule includes site-specific flexibilities to ensure reliability. While it is not always possible or necessary to harmonize the CAA and CWA requirements due to the different means by which flexibilities are implemented under the two statutes, EPA has provided flexibility under the ELG which would reasonably allow for the use of the site-specific flexibilities of the CAA section 111 rule. Specifically, since the two coal-fired EGU subcategories in the CAA section 111 final rule have compliance dates of January 1, 2030, and January 1, 2032, the use of the site-specific flexibilities tied to reliability would necessarily mean that some EGUs could retire after those dates with less stringent or delayed standards. Thus, the additional time provided by a 2034 permanent cessation of coal combustion date in the final ELG allows time for the corresponding site-specific flexibilities in the CAA 111 rule to be utilized.

While harmonization with the CAA section 111 rule supports the finding that this subcategory is appropriate, it is the EPA's intent that this new permanent cessation of coal combustion subcategory be retained even if the final CAA section 111 rule is not in effect. The EPA finds that, even in the absence of the CAA 111 rule, the other statutory factors of age, non-water quality environmental impacts, and cost are sufficient, either alone (save for cost) or together, to support the subcategory for EGUs permanently ceasing coal combustion by 2034.

b. The EPA is establishing BAT limitations for EGUs in this subcategory based on the currently applicable BAT technology bases for FGD wastewater, BA transport water, and CRL during the continued combustion of coal.

The EPA finds that the 2020 rule BAT technologies that formed the bases for the generally applicable limitations for FGD wastewater and BA transport water, as well as the BAT technologies that formed the bases for limitations in the high FGD flow subcategory and in the LUEGU subcategory, are available, are economically achievable, and have acceptable non-water quality environmental impacts, as explained in the 2020 rule and further confirmed by analyses in this rule. EPA is, therefore, identifying them as the BAT technology bases for FGD wastewater and BA transport water for EGUs in this subcategory.[131] The EPA is also declining to establish BAT limitations on CRL prior to permanently ceasing combustion of coal. The effect of EPA declining to establish BAT limitations for CRL discharged from EGUs in this subcategory prior to permanently ceasing coal combustion is that permitting authorities will continue to establish technology-based effluent limitations using their BPJ. Because the limitations are required to be derived on a case-by-case basis, taking into account the requisite statutory factors and applying them to the circumstances of a given plant, these limitations would by definition be technologically available and economically achievable and have acceptable non-water quality environmental impacts where the permitting authority supports in the record of the permit that such is the case.

The EPA rejects more stringent technologies, such as zero-discharge systems, for FGD wastewater, BA transport water, or CRL in this subcategory before the permanent cessation of coal combustion. Zero-discharge requirements for this subcategory may not allow electric utilities with a limited remaining useful life to continue their ongoing, approved plans for an organized phasing out of EGUs that are no longer economical, in favor of more efficient, newly constructed generating stations. This concern is reduced by maintaining the currently applicable BAT limitations for this subcategory.

While the previous basis is sufficient to reject technologies that would result in more stringent limitations, the EPA notes that limitations based on such technologies as zero-discharge systems would impose greater costs per MWh on this subcategory of EGUs, given their limited remaining useful life. This provides additional support for rejecting more stringent limitations. Retaining the currently applicable BAT for this subcategory alleviates the choice for these plants to either pass on the greater capital costs per MWh of zero-discharge systems over a shorter remaining useful life or risk the possibility that post-retirement rate recovery would be denied for the significant capital and operating costs associated with the final rule. In addition, with respect to CRL, requiring across-the-board BAT limitations before permanent cessation of coal combustion could lead to individual facilities experiencing disparate costs not only because of the short remaining useful life of the facility, but also because of the short remaining useful life of the waste management unit. The record indicates that the volumes of CRL generated by a retired landfill are approximately an order of magnitude lower than the volumes of CRL generated by an operating landfill. One of the primary inputs to EPA's cost model is the volume treated. Here, if the EPA mandated categorical limitations based on a treatment technology prior to ceasing combustion of coal, a facility would need to size that technology to treat the flows of a fully operating landfill. However, about 90 percent of that system would go idle only a few years later and remain idle into perpetuity. Thus, these capital investments would result in greater costs per MWh sold compared to the costs described to treat CRL discharges at plants continuing operations (see section VII.B.3 of this preamble). CRL costs for a post-retirement-sized system would be lower in absolute terms, but also lower in light of these costs being incurred later. This finding does not conflict with the EPA's finding that case-by-case BAT limitations developed using a permitting authority's BPJ are available, are economically achievable, and have acceptable non-water quality environmental impacts because a permitting authority can consider site-specific information, such as the availability of other existing wastewater treatment systems at the plant to accommodate the volumes of CRL generated.[132]

[131] In identifying the BAT technology bases of the 2020 rule as BAT for the new permanent cessation of coal combustion by 2034 subcategory, the EPA is excluding the technology bases for EGUs permanently ceasing coal combustion by 2028. These EGUs can already seek an ''as soon as possible'' date for the new 2024 limitations later than the December 31, 2028, date for the permanent cessation of coal combustion.

[132] For example, if an FGD wastewater treatment system already in place at a facility was under-

The EPA also rejects surface impoundments as BAT for FGD wastewater, BA transport water or CRL in this subcategory before the permanent cessation of coal combustion. Some commenters encouraged the EPA to finalize either a new or an extended permanent cessation of coal subcategory with surface impoundments as BAT. While EPA has today reaffirmed its 2020 rule findings that surface impoundments are BAT for the subcategory of EGUs permanently ceasing coal combustion by 2028 in the section above, part of those 2020 rule findings included the finding that more stringent technologies *were* BAT for EGUs operating beyond December 31, 2028, because those technologies are available, are economically achievable, and have acceptable non-water quality environmental impacts. The EPA received several comments in the record from utilities that have done as the EPA indicated at proposal: they have continued to move forward with implementation of the 2020 rule. These utilities discussed the significant costs associated with interim steps toward implementation such as engineering design, bidding, contracting for systems, and commencing construction. EPA acknowledges these expenditures. To the extent that costs have already been incurred, these are sunk costs that cannot be recovered, and thus the marginal impact of the rule would not interfere with power plants' already approved, ongoing plans to transition to retirement or repowering or impose disparate costs. While EPA expects that most costs will already have been incurred, the 2020 rule limitations have a ''no later than'' date of December 31, 2025, rather than this rule's ''no later than'' date of December 31, 2029, for the new, more stringent BAT limitations. Thus, even in the rare case that a facility has failed to diligently pursue treatment that would meet the 2020 rule limitations, such a facility will have an additional four years to amortize any remaining capital costs of their treatment systems before ceasing coal combustion in 2034 as compared to the amount of time they would have to amortize the capital costs of treatments systems to meet this final rule's more stringent BAT limitations. Therefore, it is less likely that the investments made to comply with the 2020 rule would interfere with the orderly transition of generating capacity for those EGUs in this subcategory.

Moreover, the EPA finds that the costs to EGUs in this subcategory for meeting the currently applicable FGD wastewater and BA transport water limitations as compared to EGUs that are not permanently ceasing coal combustion by 2034 do not justify rejecting the 2020 rule limitations in favor of BAT limitations based on surface impoundments, especially where there are more stringent technologies capable of greater pollutant discharge reduction as described above that are available, are achievable, and have acceptable non-water quality environmental impacts. This finding is further confirmed in the EPA's evaluation of the 2020 rule costs in the baseline and policy runs of IPM, both of which demonstrate that the 2020 rule limitations continue to be economically achievable. The EPA's decision to continue to require permitting authorities to develop limitations on CRL discharges is also consistent with the Fifth Circuit's decision in *Southwestern Electric Power Co.* v. *EPA.* There, the Court vacated BAT limitations for CRL based on surface impoundments, citing the EPA's statements in the record that surface impoundments do not adequately control dissolved metals and the fact that there are more stringent technologies than surface impoundments that are available to control discharges of CRL. *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1029–1030. Reserving BAT limitations for CRL discharged before an EGU permanently ceases coal combustion in this subcategory allows for the permitting authority to impose more stringent technologies as appropriate.

c. For EGUs in this subcategory, BAT limitations for CRL after the EGU permanently ceases combustion of coal are based on chemical precipitation.

The EPA expects that, unlike FGD wastewater and BA transport water, CRL will continue to be discharged even after a plant permanently ceases coal combustion. For EGUs in this subcategory, the EPA is establishing nationwide limitations for CRL on mercury and arsenic based on chemical precipitation after permanently ceasing combustion of coal. Specifically, the BAT technology basis after permanently ceasing coal combustion is a chemical precipitation system that employs hydroxide precipitation, sulfide precipitation (organosulfide), and iron coprecipitation.

With respect to BAT limitations after permanent cessation of coal combustion, the rule record is extensive in support of the EPA's finding that chemical precipitation is technologically available for the treatment of arsenic and mercury in CRL. As far back as the 2015 rule, the EPA found that four plants operated chemical precipitation systems on their CRL and, in fact, established NSPS for CRL based on chemical precipitation systems.[133] The EPA also found that chemical precipitation was in use on FGD wastewater (which EPA found was characteristically similar to CRL), metal products and machinery plants, iron and steel manufacturers, metal finishers, and mining operations (including coal mines).[134] All of these uses have demonstrated the ability of chemical precipitation technology to remove arsenic and mercury.[135]

One commenter suggested that chemical precipitation does not treat dissolved arsenic concentrations. This comment contradicts what is known about chemical precipitation. In the 2015 rule record, the EPA explained that chemical precipitation systems typically use pH adjustment to make soluble forms of pollutants insoluble. The EPA found that most systems operate with three chemicals that are added in one tank or in separate tanks, depending on the pH at which individual metals will settle out.[136] Thus, while plants may need to adjust systems until it is optimized for the specific CRL and target pollutant removals, the EPA sees nothing to indicate that dissolved arsenic concentrations are not treatable just because they are dissolved. The pre- and post-treatment dissolved arsenic data the commenter refers to are a subset of total arsenic (not just dissolved arsenic) that the EPA noted in 2015 was very low (near or below the limit of quantification). The fact that some data points are above the limit of quantitation does not change the fact that these are still very low dissolved arsenic numbers that demonstrate the ability of the technology to meet the established limitations. The fact that the technology did not continue to remove arsenic below the treatment levels that the EPA established in 2015 does not negate the fact that this same data

utilized, the permitting authority might find that treatment with that system is available, economically achievable, and has acceptable non-water quality environmental impacts for that facility.

[133] U.S. EPA (Environmental Protection Agency). 2015. *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.* September. Washington, DC 20460. EPA–821–R–15–007. Available online at: *https://www.epa.gov/sites/default/files/2015-10/documents/steam-electric-tdd_10-21-15.pdf.*

[134] *Id.*

[135] *Id.*

[136] *Id.*

demonstrates the technology *does* remove arsenic down to that limit.

Another commenter referenced 2010 survey data as showing elevated levels of iron, aluminum, and manganese in CRL from landfills where coal-handling byproducts were also disposed, which this commenter suggested would make treatment more complex. The commenter did not claim that these elevated influent concentrations make the waste untreatable through chemical precipitation, only that there may be additional solid wastes or a need for multiple treatment vessels. Without more information, the EPA has no reason to conclude that chemical precipitation would not work as intended in these scenarios.[137]

The EPA finds that BAT limitations based on chemical precipitation for EGUs discharging CRL after permanently ceasing coal combustion in this subcategory are economically achievable based on the results of IPM modeling, as explained in sections VII.F and VIII.

The EPA finds that BAT limitations based on chemical precipitation for EGUs discharging CRL after permanently ceasing coal combustion in this subcategory have acceptable non-water quality environmental impacts as discussed in sections VII.G and X.

For a further discussion of the availability timing of these limitations, see section VII.E of this preamble.

d. The EPA rejects surface impoundments as BAT for CRL after permanent cessation of coal combustion in this subcategory.

The EPA finds that surface impoundments are not BAT for CRL after permanent cessation of coal combustion for EGUs in this subcategory. The record shows that chemical precipitation is available, is economically achievable, and has acceptable non-water quality environmental impacts for treatment of CRL discharges after the permanent cessation of coal combustion. Moreover, chemical precipitation removes more pollutants than surface impoundments, which better achieves the BAT requirement of making reasonable further progress toward the CWA's goals. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1003, 1006 (citing *Nat'l Crushed Stone* v. *EPA,* 449 U.S. at 75).

e. The EPA rejects more stringent technologies as BAT for CRL after permanent cessation of coal combustion in this subcategory.

The EPA finds that more stringent technologies are not BAT for CRL after permanent cessation of coal combustion for EGUs in this subcategory based on the statutory factors of age and cost, as well as given certain information gaps in the record. Specifically, the EPA finds that more stringent technologies are not commensurate with the age of the facility being in a retired status, which would lead to unacceptably higher capital costs that can no longer be spread over electricity sales.

Concerning CRL generated after retirement, the EPA notes that CRL will continue to be generated into perpetuity without any associated revenue stream tied to ongoing coal combustion, as several commenters pointed out.[138] This differs substantially from scenarios involved in a typical ELG, for which the EPA conducts a screening economic analysis that compares costs to revenues at the facility level in addition to the owner level.[139] The EPA notes that this results not in a standard disparate cost, but rather an overall disparate circumstance. Since this unique scenario does not often play out in ELGs, the EPA does not have examples to draw from in evaluating economic achievability.

Given this unique aspect of this ELG, the EPA notes that any treatment system built to operate only after the permanent cessation of coal combustion will necessarily experience costs in a differing circumstance when compared to the costs recovered via ongoing electricity sales by EGUs not in this subcategory. For CRL that is not otherwise subcategorized in this rule, the EPA is requiring limitations based on zero-discharge systems during operations to continue to apply even after retirement. These EGUs will continue to combust coal beyond 2034, so systems will already be partially or fully paid for with rate recovery from electricity sales during the active phase of the EGU. Thus, the marginal cost of continuing to use such an existing treatment system are limited to O&M costs, and thus would not result in capital costs being incurred under the disparate circumstance of retired coal-fired EGUs.

As this discussion demonstrates, the selected BAT basis, chemical precipitation, already imposes costs in a disparate circumstance compared to EGUs not in this subcategory. Compared to chemical precipitation systems, however, biological and zero-discharge systems worsen already existing situational revenue disparities based on the already passed retirement age for these EGUs when compared to the rest of the industrial category. Both chemical precipitation plus biological treatment systems and zero-discharge systems typically have capital costs about double the capital costs of chemical precipitation systems alone.[140] The EPA finds that the increased costs of these more stringent technologies renders them unacceptable in light of the post-retirement age of the EGUs to which they would apply. The EPA intends the age, cost, and economic achievability rationale discussed here is unique to the small number of industry-wide discharges at retired facilities with no revenue such as the landfill industrial point source category: it thus will not form a precedent for evaluating costs and economic achievability at the vast majority of facilities which continue to operate and have active revenue streams.

The EPA also considered the availability of biological treatment systems for CRL at closed landfills. Some commenters raised concerns that biological treatment systems could not handle low or fluctuating flows associated with CRL. The EPA agrees, in part, with these comments. Biological treatment systems require a minimum amount of feed source for the microorganisms to survive. While facilities have demonstrated the ability to supplement these nutrients in the FGD wastewater context, CRL generated after a landfill is closed is precipitation-dependent and may not be as easy to

[137] The EPA also notes that, should a facility with such a landfill generate CRL that is sufficiently different from the CRL evaluated in the record, the facility may be able to apply for a Fundamentally Different Factors variance.

[138] The EPA acknowledges that this subcategory also applies to fuel conversions. The EPA considered the fact that this subset of EGUs within this subcategory would have a future revenue stream, unlike EGUs that permanently retire. However, were the EPA to require more stringent treatment at this subset of EGUs, the result could be for a facility converting to natural gas (for example) to instead construct its replacement gas-fired capacity on an immediately adjacent greenfield to avoid the additional costs of treatment. This is a perverse incentive because it could implicate the development of additional land, perhaps even a greenfield, and construction of new transmission lines. These are adverse non-water quality environmental impacts that the EPA finds unacceptable, and it is thus declining to treat this subset differently from retiring EGUs. The EPA further notes that this outcome would result in additional costs of replacement capacity without achieving any additional pollutant discharge reductions.

[139] While The EPA has performed that comparison here using the operating revenues prior to the cessation of coal combustion, the Agency has already found that subcategorization is warranted for a number of reasons and justified retaining the current requirement that case-by-case BPJ determinations be made by the permitting authority in controlling CRL discharges.

[140] For biological treatment cost comparisons, the EPA is using the 2020 rule record with respect to FGD wastewater.

forecast as FGD wastewater flows. Thus, even if facilities provided a supplemental feed source, it would be possible to develop either too large or too small a bacterial colony. The EPA's record demonstrates that hydrogen sulfide formation can result from biological treatment when oxidation reduction potential (ORP) is too low. Sulfide produced in the system readily forms metal complexes with other metals and precipitate out of the FGD wastewater. During backwashing events, the system releases any trapped gasses generated in the process, including hydrogen sulfide (DCN SE02955). The EPA notes that large concentrations of sulfides are only a problem if the ORP goes too low for a long time.[141] The EPA's record lacks evidence of a biological treatment system operating on a retired landfill; therefore, no information is available on whether other issues related to biological treatment of CRL from retired landfills affect ORP or hydrogen sulfide production. In the absence of any record evidence of a biological treatment system operating on a retired landfill, the EPA concludes that these concerns, together with the age of the EGUs being in a retired status and the cost considerations regarding biological treatment discussed above, justify rejecting this technology as BAT for CRL post-cessation of coal combustion.

Zero-discharge systems can adapt to changes in flow rates more easily than biological treatment. Nevertheless, as with biological treatment, the record does not contain any information on zero-discharge systems operating on CRL or non-CCR landfill leachate after a facility has retired. The examples EPA has demonstrating availability consist of co-treatment with FGD wastewater or treatment of non-CCR landfill leachate during operations. During the development of this rule, the EPA sought information on treatment of CRL or non-CCR landfill leachate through vendors of applicable systems, but there were no known installations on retired landfills were indicated. While it may be possible for the EPA to establish zero-discharge systems even in record absence of operations post-cessation of coal combustion, when this information gap is combined with the age and cost considerations discussed above, it leads the EPA to conclude that zero-discharge systems do not represent BAT for post-cessation of coal combustion discharges of CRL in this subcategory.

[141] For FGD wastewater, EPA recommends ORP monitors to avoid these scenarios.

f. The EPA is not including legacy wastewater in the permanent cessation of coal combustion subcategory.

The EPA received some comments suggesting that any new permanent cessation of coal combustion subcategory should cover discharges of legacy wastewater from EGUs in the subcategory. These comments did not provide information demonstrating that legacy wastewater discharges are tied to the marginal operating costs of steam EGUs. Rather, the record demonstrates that legacy wastewater discharges will primarily continue to occur through the dewatering of surface impoundments closing under the CCR regulations. Since treatment of legacy wastewater will occur whether an EGU continues to burn coal or not, investments made under this rule do not have the potential to interfere with the orderly transition of generating capacity, as they would be incurred even if the EGU had ceased operations years ago. Moreover, because the costs must be incurred whether or not the EGU closes, these costs do not differ based on the remaining useful life of the EGUs. Since the EPA does not find that the statutory factors discussed above as the bases to establish this subcategory would apply to legacy wastewater, the EPA is not subcategorizing legacy wastewater based on the permanent cessation of coal combustion. Instead, the case-by-case limitations described in section VII.B.4 of this preamble will continue to apply.

g. The EPA is finalizing post-coal combustion cessation zero-discharge limitations for EGUs in this subcategory to avoid circumvention.

As with the permanent cessation of coal combustion by 2028 subcategory, the EPA proposed to include zero-discharge limitations applicable after the permanent cessation of coal combustion date for this subcategory, December 31, 2034. The EPA received comments that opposed the finalization of this subcategory, but in the alternative these commenters advocated for post-coal combustion cessation limitations to help ensure that the cease combustion of coal criterion for the subcategory is met. EPA also received more general comments as described in section VII.C.3 of this preamble.

After considering these comments, and for the same reasons set forth in section VII.C.3 of this preamble, the EPA is finalizing a tiered set of zero-discharge BAT limitations that apply following the cease combustion of coal by 2034 date, as follows:

- The first tier of these limitations is composed of zero-discharge limitations for FGD wastewater and BA transport water after April 30, 2035.[142] These limitations would apply if the EGU has in fact permanently ceased coal combustion as it represented it would. As suggested in the comments, this is 120 days after the latest permanent cessation of coal combustion date, allowing for facilities to complete any necessary residual decommissioning discharges.[143]
- The second tier is composed of zero-discharge limitations for the same wastewaters, as well as CRL, after December 31, 2034. If a plant fails to cease combustion of coal by 2034 (as it represented it would) for any reason other than those specified in § 423.18, these zero-discharge limitations would automatically apply.

As explained in section VII.C.3 of this preamble, the EPA finds that together, the zero-discharge limitations and reporting and recordkeeping requirements are sufficient to ensure that facilities do not unfairly benefit by continuing to discharge after the subcategory's permanent cessation of coal combustion date.

5. Discharges of Unmanaged CRL

The EPA is establishing a new subcategory for discharges of unmanaged CRL, which EPA is defining in this rule to mean the following: (1) discharges of CRL that the permitting authority determines are the FEDD to a WOTUS through groundwater or (2) discharges of CRL that has leached from a waste management unit into the subsurface and mixed with groundwater before being captured and pumped to the surface for discharge directly to a WOTUS.[144] After evaluating public comments, and in light of the factors specified in CWA section 304(b)(2)(B), the EPA finds that the record demonstrates such a subcategory is warranted based on the unacceptably high costs to the plants in this subcategory associated with zero-discharge requirements, which would

[142] The EPA is also finalizing requirements that the BAT limitations for CRL in this subcategory be met no later than April 30, 2035, to align with the dates in this backstop provision. For further discussion, see section VII.E of this preamble.

[143] The EPA notes that these do not include discharges of legacy wastewaters from surface impoundments closing under the CCR rule, which are covered by different regulatory provisions.

[144] The latter type of unmanaged CRL is no different than the former except that it is already being collected for treatment and discharge as of the effective date of the final rule. Since migration from the waste management unit and mixing with groundwater occurs in both cases, the characteristics and volumes of these two types of unmanaged CRL are expected to be consistent and, therefore, have been modeled consistently for the cost analysis discussed in section VIII.A of this preamble.

otherwise apply to CRL discharges under this rule (see discussion below). For units with discharges in this subcategory, The EPA is finalizing the proposed mercury and arsenic limitations, based on chemical precipitation, which the record shows are available, are economically achievable, and have acceptable non-water quality environmental impacts. A discussion of the selected technology basis, as well as rejected technology bases, appears below, following two subsections that address several overarching comments the EPA received about discharges in this subcategory.

The EPA solicited comment on an option to subcategorize EGUs with discharges through groundwater. Leachate is typically managed through the use of a liner and leachate collection system. In the context of municipal solid waste landfills and hazardous waste landfills, a leachate collection system is designed to maintain less than a 30-centimeter depth over the liner.[145] [146] As stated in *Solid Waste Disposal Facility Criteria Technical Manual:*

> The primary function of the leachate collection system is to collect and convey leachate out of the landfill unit and to control the depth of the leachate above the liner. The leachate collection system (LCS) should be designed to meet the regulatory performance standard of maintaining less than 30 cm (12 inches) depth of leachate, or ''head,'' above the liner. The 30-cm head allowance is a design standard and the Agency recognizes that this design standard may be exceeded for relatively short periods of time during the active life of the unit. Flow of leachate through imperfections in the liner system increases with an increase in leachate head above the liner. Maintaining a low leachate level above the liner helps to improve the performance of the composite liner.[147]

In contrast, many CCR landfills and surface impoundments have unmanaged CRL, which is allowed to percolate out of the WMU and into the subsurface and this subcategory applies to such unmanaged CRL. Specifically, the final subcategory covers such discharges of CRL that are determined, on a case-by-case, site-specific basis by the permitting authority to constitute the FEDD to a WOTUS. The EPA is also including certain direct discharges of CRL in this subcategory—in particular, discharges of CRL that has leached from a waste management unit into the subsurface and mixed with groundwater before being captured and pumped to the surface—because the EPA is aware that some plants could independently choose to pump and treat groundwater as a result of the CCR regulations, sometimes before wastewater from the impoundments traveling through groundwater has reached a WOTUS and become the FEDD to a WOTUS. This subcategory applies to any direct discharges of such CRL to a WOTUS. Both types of unmanaged CRL could occur at a plant with an unlined WMU, and both present the same basic issues in terms of costs for treatment, given the volumes of wastewater that would need to be treated to meet BAT limitations for unmanaged CRL.

a. The EPA has CWA authority to regulate certain discharges through groundwater from landfills and surface impoundments.

The EPA proposed that CRL limitations would apply not only to traditional end-of-pipe discharges, but also to discharges of CRL through groundwater, which a permitting authority deems to be the FEDD from a point source to a WOTUS. EPA received many comments related to the discharge of CRL through groundwater. Comments expressed varying views as to whether CRL discharged through groundwater from landfills and surface impoundments would be the FEDD.

As a threshold matter, as it explained in the proposed rule, the EPA is not determining that all discharges through groundwater from landfills and surface impoundments are the FEDD from a point source to a WOTUS. Rather, in this rule, the EPA is establishing limitations that apply to any discharge of this kind that a permitting authority or facility owner or operator determines to be the FEDD from a point source to a WOTUS, and thus requires an NPDES permit. The threshold standard for the ''functional equivalence'' determination is outside the scope of this rule.

Some comments argue that the EPA lacks the legal authority to regulate *any* leachate that reaches navigable waters through groundwater from landfills or surface impoundments because landfills and surface impoundments are not point sources. These comments cite two cases in support of this position. *See Sierra Club* v. *Va. Elec. & Power Co.,* 903 F.3d 403 (4th Cir. 2018); *Ky. Waterways All. V. Ky, Utils. Co.,* 905 F.3d 925 (6th Cir. 2018). Related comments suggest that, in *County of Maui,* there were unique facts regarding the existence of a point source that are not applicable in the CRL context.

In response to these comments, the EPA reaffirms its longstanding position, which is consistent with the *Maui* decision: a point source determination is case-specific, and some landfills and surface impoundments may likely meet the definition of point sources under the CWA. ''The term 'point source' means any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft, from which pollutants are or may be discharged.'' 33 U.S.C. 1362(14). At least some of the landfills and surface impoundments at steam electric facilities may fit this definition, in that they are ''discernible, confined, and discrete conveyances.'' A permitting authority may also deem surface impoundments at these facilities to be analogous to ''wells'' or ''containers'' some of the illustrative examples in the definition. As the Fifth Circuit noted in *Southwestern Elec. Power Co.* v. *EPA,* where leachate occurs at a steam electric power plant, it is typically collected and transported to an impoundment, and ''[u]nlined landfills or impoundments simply 'allow the leachate to potentially migrate to nearby ground waters, drinking water wells, or surface waters.' '' 920 F.3d at 1011 (citing the 2015 rule preamble); *id.* at 1029 (noting that the EPA's environmental assessment document reports that ''[c]ombustion residual leachate can migrate from the site in the ground water at concentrations that could contaminate public or private drinking water wells and surface waters, even years following disposal of combustion residuals'') (citation omitted). And the Fifth Circuit had earlier addressed the question of whether sump pits into which miners channeled contaminated runoff and which sometimes overflowed to ''waters of the United States'' were point sources, holding on these facts that ''[g]ravity flow, resulting in a discharge of a pollutant into a navigable water, may be a point source discharge if the miner at least initially collected or channeled the water and other materials.'' *Sierra Club* v. *Abston Construction Co., Inc.,* 620 F.2d 41, 45 (5th Cir. 1980). Under this rule, permitting authorities will continue to determine whether a particular landfill or surface impoundment meets the definition of point source, and then they will determine whether or not that point source has a discharge of pollutants subject to the CWA.

To the extent that the Fourth Circuit's decision in *Sierra Club* v. *Va. Elec. & Power Co.* held that an impoundment can never be a ''point source'' under the CWA, the Supreme Court's decision in

[145] 40 CFR 258.40(a)(2).

[146] 40 CFR 264.251(a)(2).

[147] U.S. EPA (Environmental Protection Agency). 1993. *Solid Waste Disposal Facility Criteria Technical Manual.* November. EPA530–R–93–017.

Maui calls that holding into question.[148] While commenters correctly point out that the parties in *Maui* conceded that there was a point source, so the issue was not directly before the Court, the injection wells at issue in *Maui* are factually very similar to some EGU surface impoundments. The Supreme Court in *Maui* described the facts of the case as a wastewater reclamation facility that ''collects sewage from the surrounding area, partially treats it, and pumps the treated water through four wells hundreds of feet underground. This effluent, amounting to about 4 million gallons each day, then travels a further half mile or so, through groundwater, to the ocean.'' *County of Maui,* 590 U.S. at 171. Furthermore, the Supreme Court rejected EPA's argument that ''all releases of pollutants to groundwater'' are excluded from the scope of the permitting program, ''even where pollutants are conveyed to jurisdictional surface waters via groundwater,'' in part because of the definition of ''point source,'' concluding:

> It is difficult to reconcile EPA's interpretation with the statute's inclusion of ''wells'' in the definition of ''point source,'' for wells most ordinarily would discharge pollutants through groundwater. And it is difficult to reconcile EPA's interpretation with the statutory provisions that allow EPA to delegate its permitting authority to a State only if the State (among other things) provides ''adequate authority'' to ''control the disposal of pollutants into wells.'' § 402(b), 86 Stat. 881. What need would there be for such a proviso if the Federal permitting program the State replaces did not include such discharges (from wells through groundwater) in the first place?

County of Maui, 590 U.S. at 181.

Similarly, some EGU impoundments, like wells, may discharge through groundwater to a WOTUS in a manner that is the FEDD. For example, suppose leachate from a coal-fired power plant is collected and contained in a waterfront surface impoundment dug below the groundwater table, and the leachate flows through the groundwater into the nearby ''water of the United States.'' Excluding such a discharge from CWA permitting requirements would create a loophole in the Act's coverage similar to the one that concerned the Supreme Court in *Maui:* ''We do not see how Congress could have intended to create such a large and obvious loophole in one of the key regulatory innovations of the Clean Water Act.'' *County of Maui,* 590 U.S. at 178–79. *Cf. California ex rel. State Water Resources Control Bd.,* 426 U.S., at 202–204 (basic purpose of Clean Water Act is to regulate pollution at its source); *The Emily,* 9 Wheat. 381, 390 (1824) (rejecting an interpretation that would facilitate ''evasion of the law'').

Thus, to the extent that landfills, surface impoundments, or other features that could be considered point sources and from which FEDDs of CRL occur to a WOTUS, this rule informs the permitting authority of the appropriate technology-based effluent limitations that would apply. At this time, the EPA cannot agree with commenters who presume to know the extent of such potential discharges. The EPA need not speculate as to the myriad of possible scenarios. Determining which impoundments and landfills meet the definition of ''point source'' is a task for permitting authorities and outside the scope of this rulemaking. Instead, the EPA points out that, based on current law and facts as they appear in the record, the CRL limitations the EPA is promulgating will apply to *some* discharges from *some* impoundments and landfills—*i.e.,* those that a permitting authority determines to be the FEDD from a point source to a WOTUS.

b. Potential interactions with RCRA and the CCR regulations do not justify rejection of a nationwide BAT for certain CRL discharges through groundwater.

With respect to RCRA and the CCR regulations, some commenters stated that regulation of CRL discharged through groundwater would ''nullify'' the CCR regulations in violation of RCRA's industrial wastewater exclusion or anti-duplication provision. Other commenters argued that imposing any CWA requirements on FEDDs of CRL could not be harmonized with RCRA requirements found in the CCR regulations and recommended that the EPA leave such discharges to be managed by the CCR program and states. Each of these comments is addressed in a separate discussion below.

RCRA industrial wastewater exclusion. The EPA disagrees with commenters stating that establishing BAT limitations for certain CRL discharges through groundwater would ''nullify'' the CCR regulations due to RCRA's industrial wastewater exclusion. At the outset, as explained above, this rule does not address the scope of the CWA, as it does not address which discharges may require an NPDES permit, but rather it establishes appropriate technology-based limitations to include in such a permit. Since this rule does not expand CWA jurisdiction over any discharges—in particular, it does not require CWA regulation of discharges, such as certain CRL discharges through groundwater, that would not already be regulated by the CWA—it does not alter the existing RCRA framework that accounts for the CWA.

The EPA also disagrees with commenters that regulation of certain CRL discharges through groundwater would block regulation by the CCR regulations. RCRA excludes from the definition of ''solid waste'' any ''industrial discharges which are point sources subject to permits'' under the CWA. 42 U.S.C. 6903(27). As the EPA has explained before, this RCRA exclusion applies to discharges to jurisdictional waters under the CWA, and not to any activity, including groundwater releases or contaminant migration, that occurs prior to that point. The EPA explained this in more detail in a ''Question and Answer'' on the EPA's website:

> Does the issuance of an NPDES permit covering discharges from a CCR unit exempt the owner/operator from any requirements under the CCR rule?
>
> No, discharges covered by an NPDES permit are not a ''solid waste'' pursuant to RCRA section 1004(27). The RCRA exclusion only applies to ''industrial discharges that are point sources subject to permits,'' *i.e.,* to the discharges to jurisdictional waters, and not to any activity, including groundwater releases or contaminant migration, that occurs prior to that point. See title 40 of the Code of Federal Regulations (CFR) 261.4(a)(2) (''This exclusion applies only to the actual point source discharge. It does not exclude industrial wastewaters while they are being collected, stored or treated before discharge.''). For purposes of the RCRA exclusion, EPA considers the ''actual point source discharge'' to be the point at which a discharge reaches the jurisdictional waters, and not in the groundwater or otherwise prior to the jurisdictional water. Thus, the issuance of an NPDES permit for discharges from a facility's CCR surface impoundment would not exempt the owner/operator from any requirements under the CCR rule applicable to the disposal unit, such as the requirements to ensure the structural stability of the unit, to clean up all releases to the aquifer, and to meet all closure standards.[149]

Compare RCRA's ''solid waste'' definition, 42 U.S.C. 6903(27), with the CWA's definition of the ''discharge of pollutants,'' 33 U.S.C. 1362(12) (''any addition of any pollutant to navigable waters from any point source''). Until the point at which the discharge reaches

[148] The decision in *Ky. Waterways All.* v. *Ky, Utils. Co.,* 905 F.3d 925, cited by some commenters did not address the question of whether an impoundment is a point source but rather held that ''The CWA does not impose liability on surface water pollution that comes by way of groundwater.'' The decision has been abrogated by *Maui.*

[149] Available online at: *https://www.epa.gov/coalash/relationship-between-resource-conservation-and-recovery-acts-coal-combustion-residuals-rule.*

''navigable waters,'' any collection, storage, treatment, or even groundwater contamination is still subject to RCRA and the requirements of the CCR regulations.

RCRA anti-duplication provision. The EPA also disagrees with commenters who asserted that regulation of certain CRL discharges through groundwater would be inconsistent with or duplicative of regulation by the CCR regulations due to RCRA's anti-duplication provision. RCRA, by its terms, requires administration and enforcement that is ''not inconsistent'' with, among other Federal statutes, the CWA. 42 U.S.C. 6905(a). It further requires both integration and non-duplication with the CWA ''to the maximum extent *practicable.*'' 42 U.S.C. 6905(b) (emphasis added). The requirements do not mean there can be no overlap to accomplish the purposes of each statute.

Circuit courts have found several similar instances of RCRA and the CWA operating in tandem.[150] For example, in *Goldfarb* v. *Mayor and City Council of Baltimore,* 791 F.3d 500 (4th Cir. 2005), construction activities allegedly spread/worsened existing soil, water, and groundwater contamination. The defendants maintained their NPDES permit shielded them from RCRA liability because of RCRA's anti-duplication provision. The court rejected this contention, explaining:

> To be ''inconsistent'' for purposes of [RCRA's] § 6905(a), then, the CWA must require something fundamentally at odds with what RCRA would otherwise require . . . RCRA mandates which are just different, or even greater, than what the CWA requires, are not necessarily the equivalent of being ''inconsistent'' with the CWA. . . . It is not enough that the activity or substance is already regulated under the CWA; it must also be ''incompatible, incongruous, and inharmonious.'' . . . The district court's conclusion is thus built on the faulty premise that the CWA and RCRA cannot regulate the *same* activity under any circumstance.

Goldfarb v. *Mayor and City Council of Baltimore,* 791 F.3d at 505–06, 510. Similarly, *Ecological Rights Foundation* v. *Pacific Gas & Electric Co.,* 874 F.3d 1083 (9th Cir. 2017), involved an action against owners of mining activities that allegedly leached toxic substances into navigable waters. The court held that so long as RCRA's application is not ''inconsistent'' with the CWA, the anti-duplication provision is no bar to a RCRA action. *Id.* at 1089, 1095–97 (collecting cases and a Department of Justice Office of Legal Counsel opinion). It further held that the term ''inconsistent'' must be ''mutually repugnant or contradictory'' such that ''one implies abrogation or abandonment of the other.'' *Id.* at 1095 (citations omitted). The case expressly recognized that there can be overlap between these regulatory schemes. Since case law generally supports the operation of the CWA in tandem, not *in lieu* of RCRA, the EPA disagrees with commenters. *See also Chemical Waste Management* v. *EPA,* 976 F.2d 2, 23, 25 (D.C. Cir. 1992).

Practical interaction of the CCR and ELG rules. The EPA also disagrees with commenters who stated that imposing any CWA requirements on FEDDs of CRL could otherwise not be harmonized with RCRA requirements found in the CCR regulations. The RCRA CCR regulations, which post-date the CWA, were written with integration in mind. That is, 40 CFR 257.52(b) provides: ''Any CCR landfill, surface impoundment, or lateral expansion of a CCR unit continues to be subject to the requirements in §§ 257.3–1, 3–2, and 3–3.'' And 40 CFR 257.3–3(a) provides: ''For purposes of section 4004(a) of the [Resource Conservation and Recovery] Act, a facility shall not cause a discharge of pollutants into waters of the United States that is in violation of the requirements of the National Pollutant Discharge Elimination System (NPDES) under section 402 of the Clean Water Act, as amended.'' Critically, nothing in § 257.3–3(a) or other sections establish a RCRA permitting scheme for discharges to navigable waters, nor in any other ways contradicts the CWA's NPDES permit program. The CCR regulations generally, and § 257.3–3(a) specifically, leave the regulation of point source discharges to navigable waters to the CWA. The CCR regulations regulate the management of CCR to protect human health and the environment, including groundwater, from contamination associated with the mismanagement of these wastes. *See, e.g.,* 40 CFR 257.91 through 257.98. They do so because, among other important reasons, CCR is a potential source of contamination in wells used for drinking water.

Given the above, the EPA does not agree with commenters that establishing limitations for functionally equivalent CRL discharges through groundwater would conflict with the CCR regulations. Instead, the CCR regulations require CRL-contaminated groundwater to meet specific levels or to be cleaned up to those levels through corrective action. The EPA expects that in many cases this would require pump-and-treat operations.[151] To the extent that a facility elects to pump CRL-contaminated groundwater to the surface and discharge it directly, this final subcategory and corresponding limitations would apply to the end of that pipe. While groundwater monitoring may be appropriate to ensure that CRL is not evading the pump-and-treat operations and resulting in an unpermitted discharge to a WOTUS, the groundwater concentrations would not be subject to this final rule.

To further elaborate the point that the limitations established in this final rule are for surface water discharges, consider the alternatives to pump-and-treat operations. Facilities are not required to employ the specific technology of chemical precipitation established as BAT today. Some commenters specifically requested that the EPA consider the flexibility for facilities to clean close their surface impoundments or to perform *in situ* treatment or impermeable barriers. But this flexibility already exists. If a facility were to install an impermeable barrier that prevented groundwater contamination from discharging to a WOTUS, or a semi-permeable barrier that treated the discharge to remove toxic pollutants, it could satisfy the specific mercury and arsenic limitations that the EPA is finalizing. It also might be possible for facilities to avoid the need for an NPDES permit by clean closing and eliminating any point source itself. In these cases, there very well may continue to be CRL-contaminated groundwater, but this is outside the purview of the CWA because the CRL would not be reaching WOTUS, as discussed in the sections above. Thus, the EPA does not find any conflict between the CCR regulations' protection of groundwater and the establishment of BAT limitations for CRL discharged through that groundwater that is found to be the FEDD; nor does it find any way in which the two sets of requirements cannot be harmonized.

c. The EPA selects chemical precipitation as BAT for discharges of CRL in this subcategory.

For this subcategory, the EPA is establishing BAT limitations for mercury and arsenic based on chemical precipitation. Specifically, the technology basis for BAT is a chemical

[150] In contrast, the EPA acknowledges that the *Ky. Waterways All.* case found that RCRA's anti-duplication provision barred CWA authority, a finding which is not only not supported by the text of the CWA but is also to the EPA's knowledge not found in the case law of any other circuit.

[151] The EPA acknowledges that, at present, many facilities have instead selected monitored natural attenuation as a remedy even though this remedy would, by definition, patently fail to meet the cleanup standards established in § 257.97(b).

precipitation system that employs hydroxide precipitation, sulfide precipitation (organosulfide), and iron coprecipitation.

As described in section VII.C.4 of this preamble, the rule record is extensive in support of the EPA's finding that chemical precipitation is technologically available for the treatment of arsenic and mercury in CRL. As far back as the 2015 rule, the EPA found that four plants operated chemical precipitation systems on their CRL.[152] EPA also found that chemical precipitation was in use on FGD wastewater (which the EPA found was characteristically similar to CRL), metal products and machinery plants, iron and steel manufacturers, metal finishers, and mining operations (including coal mines).[153] All of these uses have demonstrated the use of chemical precipitation technology to remove arsenic and mercury.[154]

At proposal, the EPA's preferred regulatory option would have established chemical precipitation as BAT for all types of CRL discharges. Several commenters took issue with the EPA's proposed findings and BAT selection for FEDDs of CRL. These commenters stated that EPA failed to evaluate how CRL changes in groundwater. Commenters stated that differences from end-of-pipe CRL suggest that the EPA should decline to set national limitations and retain case-by-case BPJ determinations for, or alternatively require only monitoring of, FEDD of CRL at this time.

With respect to the interaction of CRL with groundwater, while the EPA received general comments about the possibility of interactions in groundwater, commenters did not provide data to demonstrate that CRL in groundwater changes to the extent that pollutant concentrations would no longer fall within the range of concentrations evaluated by the EPA for CRL. Nor did commenters provide data that CRL becomes untreatable via chemical precipitation from any such changes. Instead, comments describe ''attenuation'' such as through adsorption. However, to the extent that adsorption and other attenuation processes would *remove* pollutants, this would only make it easier for chemical precipitation to meet the established limitations.

In addition to being technologically available, chemical precipitation for this subcategory is economically achievable. At proposal, EPA could not prospectively determine how many or which instances of CRL discharged through groundwater would ultimately be found to require CWA permits. As described above, to be a covered discharge, there must be a discharge (or FEDD) of pollutants from a point source into a WOTUS. Since this determination is outside the scope of the rule, EPA examined this cost via a sensitivity analysis entitled *Evaluation of Unmanaged CRL* (DCN SE11501). The fact that EPA estimated these costs (and pollutant loadings) in a separate document from the more traditional end-of-pipe discharges does not mean that the EPA concluded that none would be subject to CWA permitting, as some commenters claimed. Neither did the EPA's assumption for the purposes of a worst-case costing analysis suggest that the EPA was concluding that all of these potential discharges would be subject to CWA permitting, as other commenters claimed. Instead, when total costs (and pollutant loadings) are viewed in conjunction with this separate analysis, they provide the range within actual costs (and pollutant loadings) are expected to fall. The EPA acknowledges that a best estimate would be helpful, but in the absence of permitting determinations on which discharges are subject to CWA permitting, the EPA declines to speculate as to the ultimate coverage. This position is consistent with the position outlined above. All that the EPA is required to do for this rulemaking is make a reasonable estimation of costs, which EPA has does done. *See Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d at 237–38.

For the final rule, EPA has updated these CRL costs in *Evaluation of Unmanaged CRL* (DCN SE11501). These engineering costs were then used to develop an upper bound and lower bound that more accurately reflects the range of costs of treating unmanaged CRL as described in section VIII.A of this preamble. Using these costs, the EPA then conducted a screening-level analysis of economic impacts, which helped inform EPA's determination that the final rule's unmanaged CRL limitations are economically achievable. For further discussion of the screening-level analysis and economic achievability, see sections VII.F and VIII.C.1 of this preamble.

The EPA notes that some commenters suggested that state permitting authorities would face an incredible regulatory burden if the rule were finalized as proposed.[155] The EPA disagrees that it is creating any additional burden to permitting authorities in finalizing this subcategory. Permitting authorities are already required to determine whether a discharge is subject to CWA permitting and to act on applications for CWA permits or certain modification requests for such permits. Furthermore, FEDDs are already subject to the CWA under *Maui.* Thus, to the extent that permitting authorities are already required to evaluate and develop technology-based and water quality-based effluent limitations for FEDDs, this existing burden will not change, regardless of the EPA's selection of BAT. If burden is changing at all, it is decreasing, because EPA is selecting chemical precipitation as BAT, as discussed in the section below. Since this replaces BPJ determinations, it means that permitting authorities can avoid BPJ analyses that they otherwise would have performed for FEDDs of CRL.

d. The EPA rejects surface impoundments as BAT for discharges of CRL in this subcategory.

The EPA is not selecting surface impoundments as BAT for FEDDs of CRL. BAT must achieve ''reasonable further progress'' toward the CWA's goal of eliminating pollution. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1003, 1006 (citing *Nat'l Crushed Stone* v. *EPA,* 449 U.S. at 75). The record shows that chemical precipitation removes more pollutants than surface impoundments and that chemical precipitation is technologically available, is economically achievable, and has acceptable non-water quality environmental impacts.

With respect to comments suggesting the EPA finalize only a monitoring requirement, the EPA does not view monitoring alone as satisfying the statutory obligation to identify BAT to control all discharges, particularly where there is a technology that can be applied to control discharges of CRL, chemical precipitation, that is technologically available, is economically achievable and has acceptable non-water quality environmental impacts. As described in section XIV.C.3 of this preamble below, however, the EPA is finalizing additional monitoring requirements to

[152] U.S. EPA (Environmental Protection Agency). 2015. *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category.* September. EPA–821–R–15–007. Available online at: *https://www.epa.gov/sites/default/files/2015-10/documents/steam-electric-tdd_10-21-15.pdf.*

[153] *Id.*

[154] *Id.*

[155] Some comments also pointed to the state amicus brief filed in *Maui,* where states made this very argument in a broader context (an argument ultimately rejected by the *Maui* Court itself).

support the implementation of the limitations in this subcategory.

e. The EPA rejects more stringent technologies as BAT for discharges of CRL in this subcategory.

EPA rejects zero-discharge systems as BAT for this subcategory. The EPA finds that the potential zero discharge costs for CRL discharges in this subcategory are unacceptably high. EPA's CRL costs as reflected in *Evaluation of Unmanaged CRL* (DCN SE11501) show that the capital costs of zero-discharge treatment could range as high as $17.4 billion while O&M costs could range as high as $2.04 billion per year. The annualized total costs of zero discharge could be as high as $3.69 billion. These costs are nearly an order of magnitude higher than total costs to the industry for all of the remaining end-of-pipe discharges from every wastestream combined (including costs associated with discharges of CRL that is not covered by this subcategory). The EPA finds that these additional zero discharge costs are unreasonable. Costs are one of the statutory factors that the EPA must consider, and courts have found that the EPA can properly rely on costs in rejecting potential BAT technologies. *See e.g., BP Exploration & Oil Inc.* v. *EPA,* 66 F.3d 784, 799–800 (6th Cir. 1995).[156] For further discussion of costs and economic achievability, see sections VII.F and VIII.

The EPA also rejects chemical precipitation plus low hydraulic residence time biological reduction as BAT for this subcategory. While no commenter recommended that the EPA select chemical precipitation plus low-hydraulic-residence-time biological reduction as BAT for discharges of CRL in this subcategory, the record does contain two plants treating traditional, end-of-pipe CRL with biological treatment. The EPA does not have sufficient data from these plants on which to base possible limitations. Therefore, the EPA declines to identify chemical precipitation plus biological treatment as BAT.[157]

[156] The high costs in this case were estimated to be about $3 billion in capital costs, or $6.7 billion after adjusting for inflation to 2023 dollars. The EPA notes that the $17.4 billion in capital costs for zero discharge here, even if only half of such discharges are covered, would still be higher (about 2.5 times).

[157] Although the EPA did not conduct a sensitivity analysis on costs of this technology as it did for chemical precipitation or zero discharge, the EPA notes that this cost would be between these two costs based on the cost estimation results of the previous rulemakings. Since these costs would be higher than chemical precipitation alone, they may also be unacceptably high, as are the costs for zero discharge.

6. Legacy Wastewater Discharged From Surface Impoundments Commencing Closure After July 8, 2024

The EPA is establishing a new subcategory for legacy wastewater discharged from surface impoundments which commence closure under the CCR regulations after July 8, 2024. For units in this subcategory, the EPA is establishing mercury and arsenic limitations based on chemical precipitation. More specifically, the technology basis for BAT includes the same chemical precipitation system described in the 2015 rule, which employs hydroxide precipitation, sulfide precipitation (organosulfide), and iron coprecipitation.

At proposal, the EPA solicited comment on a legacy wastewater subcategory for composite-lined surface impoundments that meet the location restrictions of the CCR regulations. In contrast to most surface impoundments, the EPA identified 22 surface impoundments at 17 facilities in *Legacy Wastewater at CCR Surface Impoundments* (DCN SE10252) that the record indicated met these criteria. The EPA solicited comment on this subcategory because its view was that these surface impoundments can continue to operate and thus would likely not begin closure and dewatering until after the effective date of any final ELG. Since these surface impoundments would not already be in the midst of dewatering under the tight closure timeframes of the CCR regulations, these facilities would have time to develop a CCR closure plan that included wastewater treatment during the dewatering phase of closure. Many commenters were opposed to the establishment of such a subcategory based on liner type. The EPA also received comments, however, recommending that, in order to address the issue that it had raised at proposal about potentially differentiated limitations for certain impoundments that have not already begun to dewater, a legacy wastewater subcategory should be created that is defined based on a deadline under the CCR regulations.

After considering the comments received and evaluating the record in light of the factors specified in CWA section 304(b)(2)(B), the EPA concludes that a subcategory is warranted for certain legacy wastewater discharges based on process changes at these plants happening under the CCR regulations. First, the EPA agrees with commenters that a liner-based subcategory would be inappropriate. On the one hand, some composite-lined surface impoundments may have already commenced closure under the CCR regulations. Thus, a subcategory that included these units would still include surface impoundments in the midst of closure under the tight deadlines of the CCR regulations, the very scenario described in section VII.B.4 of this preamble, for which the EPA found it is inappropriate to establish nationwide BAT limitations. On the other hand, the CCR regulations include flexibilities that allow a facility needed for reliability to continue to receive waste in an unlined surface impoundment or to make an alternate liner demonstration to continue to receive waste in an unlined surface impoundment. In both cases, the unlined surface impoundment could continue operation and not commence closure until after the ELG effective date. Thus, similar to the lined units discussed at proposal, these facilities would be able to build wastewater treatment into their closure plans. As is apparent from this discussion, a subcategory based on liner type is potentially both overinclusive and underinclusive, which was not the EPA's intent.

The EPA does, however, agree with comments suggesting an alternative subcategory designation more appropriately aligned with the EPA's intent and tied to the regulatory triggers in the CCR rule. It was suggested that the EPA consider using the CCR regulations' cease receipt of waste date; however, after a more thorough examination of 40 CFR part 257, the EPA finds that the ''commence closure'' date of § 257.102(e) is the appropriate regulatory trigger. This provision applies to surface impoundments that are not closed for cause (*i.e.,* unlined or failing location restrictions), but rather because the surface impoundment will no longer be used.[158] This subcategorization solves the dual problem described for the proposed liner-based subcategorization above. If a lined surface impoundment has already commenced closure under § 257.102(e), then it would not be subject to this subcategory, and if an unlined surface impoundment is continuing to operate under one of the CCR rule flexibilities, then it will not yet have commenced closure pursuant to this provision. Thus, the final rule subcategory captures only surface impoundments that are not in the midst of closure, as the proposed rule intended. While the

[158] Commencing closure is triggered when a unit ceases receipt of waste or ceases extraction of materials for beneficial use, though facilities are also permitted to postpone this commence closure date if they make a filing that the facility intends to restart the receipt of waste or extraction of materials for beneficial use at a specific future date.

EPA declined to establish nationwide BAT limitations for legacy wastewater in section VII.B.4 of this preamble based on process changes, specifically the ongoing closure of these units under the CCR rule, the EPA finds that this factor is inapplicable to the legacy wastewater that will be discharged in the future at these subcategorized surface impoundments.

a. The EPA selects chemical precipitation as BAT for legacy wastewater in this subcategory.

Since nationwide limitations are appropriate for this subcategory, the EPA next evaluates the final rule technology basis of chemical precipitation. For this subcategory of legacy wastewater discharges, EPA is establishing chemical precipitation-based limitations, as they are available, are economically achievable, and have acceptable non-water quality environmental impacts, as described below.

The EPA finds that chemical precipitation is available to treat legacy wastewater in this subcategory. At the time of the 2015 rule, the Agency acknowledged that chemical precipitation was being used on legacy wastewater discharges comprised of ash transport water. 80 FR 67855. Since that time, the EPA has learned of additional use on legacy wastewater of chemical precipitation at two Duke facilities and an SDE system at Boswell Energy Center. In addition to the use of chemical precipitation at a number of legacy wastewaters domestically, the EPA notes that, in the 2015 record, it did not discuss potential technology transfer of chemical precipitation-based limitations to legacy wastewater based on its performance in treating other wastestreams that comprise legacy wastewater. The Agency has consistently found, however, that two of the other three wastewaters regulated in this final rule (FGD wastewater and CRL) have the same pollutants and are amenable to treatment with the same treatment systems. As a result of this finding, the 2015 rule established NSPS for CRL based on chemical precipitation. Furthermore, in 2015, also found that CRL has the same pollutants as BA transport water, a wastewater that some facilities treated with chemical precipitation at the time of that final rule. *See* EPA–HQ–OW–2009–0819–6230. In short, the three wastewaters being regulated in this final rule for which the EPA is amending the legacy wastewater limitations have all been successfully treated with chemical precipitation systems. Based on what is known about the properties of these treatment systems, the characteristics of the various wastestreams at issue, and the demonstrated ability of chemical precipitation to treat such wastestreams, the EPA is transferring mercury and arsenic limitations from FGD wastewater and CRL to the subcategory of legacy wastewater described in this section for the final rule. As previously explained, EPA may rely on technology transfer to establish technology-based limitations such as those in this rule. *See Am. Iron & Steel Inst.* v. *EPA,* 526 F.2d at 1058, 1061, 1064; *Weyerhaeuser Co.* v. *Costle,* 590 F.2d at 1054 n.70; *Reynolds Metals Co.* v. *EPA,* 760 F.2d at 562; *California & Hawaiian Sugar Co.* v. *EPA,* 553 F.2d at 287.

The EPA also finds that the costs of chemical precipitation systems are economically achievable for the subcategory. At proposal, the EPA evaluated the costs for legacy wastewater in a sensitivity analysis. For this final rule, EPA has included these costs in its primary cost estimates and economic screening analysis. IPM, which projects decisions on dispatch of EGUs, is not affected by these costs, which occur irrespective of generation. Thus, the costs are not included in the IPM analysis. However, the cost analysis demonstrates that costs for treating this wastestream are low, a finding that is bolstered by the relatively low impacts as a percent of revenues as seen in the economic screening analysis of the final rule. (For further information, see sections VII.F and VIII.) Because the EPA is required to consider whether the cost of BAT can be reasonably borne by the industry and confers on the EPA discretion in consideration of the BAT factors, *see, e.g., Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d at 262; *Weyerhaeuser* v. *Costle,* 590 F.2d at 1045, EPA finds that these additional costs are economically achievable as that term is used in the CWA.

Finally, the EPA finds that the non-water quality environmental impacts associated with chemical precipitation systems for controlling legacy wastewater discharges in this subcategory are acceptable. See sections VII.G and X below for more details.

b. The EPA rejects less stringent technologies as BAT for legacy wastewater in this subcategory.

The EPA did not select surface impoundments as BAT for legacy wastewater in this subcategory, as surface impoundments would remove fewer pollutants than the BAT technology selected above, which is available, is achievable, and has acceptable non-water quality environmental impacts, and which will better achieve the BAT requirement of making reasonable further progress toward the CWA's goals. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1003, 1006 (citing *Nat'l Crushed Stone* v. *EPA,* 449 U.S. at 75).

c. The EPA rejects more stringent technologies as BAT for legacy wastewater in this subcategory.

The EPA is not selecting chemical precipitation plus biological treatment as BAT for legacy wastewater in this subcategory. Biological treatment requires a period of optimization for concentration and composition of the microorganisms to reach a steady state in which the reduction-oxidation activity of the microorganisms can reduce pollutants of concern without creating excessive levels of hydrogen sulfide gas. Unlike FGD wastewater, however, which is a relatively consistent wastewater that can be equalized in tanks to moderate differences before treatment, legacy wastewater being drained from a surface impoundment is known to quickly change pollutant concentrations as the surficial water is drained and dewatering progresses down through one or more layers of CCR. Due to the relatively short timelines for dewatering when compared to the equalization timeframes for the bacteria, biological reduction would not be able to consistently meet the biological treatment-based limitations established for FGD wastewater in the 2015 or 2020 rules.

The EPA is also not selecting chemical precipitation plus ZVI systems as BAT. The EPA acknowledges that it learned of a plant using this technology to treat its legacy wastewater. The EPA does not, however, have any information in the record on the influent or effluent data from this system to establish limitations, nor has the EPA developed ZVI-based limitations for any other wastestream that it can transfer. Commenters did not advocate for establishment of limitations based on ZVI systems, nor submit any information related to the performance of these systems, including data that would allow the Agency to develop numerical limitations; therefore, the EPA cannot, at this time, establish limitations based on chemical precipitation plus ZVI systems.

The EPA finds that zero-discharge systems are not BAT for legacy wastewater in this subcategory based on the statutory factor of age and cost, as well as given certain information gaps in the record. Specifically, the EPA finds that more stringent zero-discharge technologies are not commensurate with the age of the facility being in a retired status, which would lead to unacceptably higher capital costs that

can no longer be spread over electricity sales.

As described in section VII.C.4 of this preamble with respect to CRL generated and discharged after a plant retires, surface impoundment dewatering at EGUs in this subcategory is also likely to take place when a facility would no longer be generating revenue, as several commenters pointed out. Thus, any treatment system, including the selected BAT basis of chemical precipitation, built to operate only after retirement will necessarily have to incur capital costs in a disparate circumstance of a post-retirement age when compared to costs to EGUs that dewater their impoundments while still generating revenue. Compared to chemical precipitation systems, however, zero-discharge systems worsen the disparate circumstance of EGUs facing costs while in a retired status. Zero-discharge systems typically have capital costs approximately double the capital costs of chemical precipitation systems alone. The EPA finds that the increased cost of these more stringent technologies renders them unacceptable in light of the unique position of the EGUs to which they would apply. The EPA intends that the cost and economic achievability rationale discussed here is unique to the small number of industry-wide discharges at retired facilities with no revenue, and thus will not form a precedent for evaluating costs and economic achievability at the vast majority of facilities which continue to operate and have active revenue streams.

The EPA also notes that there are data gaps in the record for zero-discharge technologies. The current record reflects only a single facility employing a zero-discharge SDE system to treat legacy wastewater, and unlike Boswell Energy Center, many facilities in this subcategory will dewater and close their ash impoundments after the facility ceases generating electricity. Without electricity production, there is no slipstream of flue gas with which to operate the same type of SDE system that is achieving zero discharge at Boswell. The EPA is not aware of any other facility that is employing a zero-discharge technology, such as membrane filtration or thermal evaporation, to treat its legacy wastewater. While it is possible that the EPA could transfer non-zero numerical limitations from treatment of other wastestreams using these technologies, given the information gap and the additional costs in the context of these EGUs unique position discussed above, the EPA declines to select zero-discharge systems as BAT for legacy wastewater in this subcategory.

7. Interim Limitations Applicable to FGD Wastewater and BA Transport Water

The EPA is retaining the final 2020 rule BAT technology bases and limitations for FGD wastewater and BA transport water as interim limitations until the applicability dates of the new zero-discharge limitations (see section VII.E of this preamble for availability timing of the new requirements). Specifically, the 2020 rule established BAT limitations for FGD wastewater based on chemical precipitation plus low hydraulic residence time biological reduction or, in the case of the high FGD flow and LUEGU subcategories, based on chemical precipitation only. BAT limitations for BA transport water were based on high recycle rate systems with up to a 10 percent volumetric purge or, in the case of the LUEGU subcategory, based on surface impoundments with a BMP plan. The EPA finds that the 2020 BAT technology bases continue to be available, economically achievable, and have acceptable non-water quality environmental impacts for all of the reasons stated in the 2020 rulemaking and as supplemented by the new IPM analyses updating the Agency's economic achievability determination and further discussed below.

Although it proposed more stringent zero-discharge limitations in 2023, the Agency always intended that the 2020 rule limitations would continue to apply. For example, when EPA explained its reasoning as to why it did not postpone the requirements in the 2020 rule, it stated, ''There is no basis in the record indicating that the limitations finalized in 2020 are not available or economically achievable, and thus there is no reason for the EPA to postpone their implementation. EPA is focused on progress toward eliminating discharges, consistent with CWA section 301(b)(2)(A).'' 88 FR 18886. Similarly, the EPA's earlier announcement of this supplemental rulemaking stated (and the proposal reiterated) that ''the pollutant reductions accomplished by the existing rules will occur while the Agency engages in rulemaking to consider more stringent requirements.'' 86 FR 41802.

The EPA received many comments from electric utilities arguing that this approach was not appropriate. Some commenters claimed that the EPA should have halted implementation while it considered rule revisions. Some commenters stated that costs of the 2020 rule technologies would not be fully recovered over the timeframe before new, more stringent limitations would come into effect. Others described these costs as high, or potentially drawing investment away from the transition to cleaner energy sources. One commenter claimed that the EPA violated its own policy of only revisiting ELGs for seven years after a final regulation is issued. Finally, the EPA received comments that the 2020 rule limitations were well founded.

After considering public comments, including those mentioned above, the EPA is retaining the 2020 rule limitations applicable to FGD wastewater and BA wastewater as interim limitations before the applicability dates of the zero-discharge limitations finalized. The EPA disagrees that it should have halted implementation of the 2020 rule. The EPA found the 2020 rule technologies to be available, economically achievable, and to have acceptable non-water quality environmental impacts. While the EPA agrees that cost recovery periods for the 2020 rule technologies will be curtailed, and that it is possible that this would divert investment dollars from clean energy projects, the record shows that the total costs of implementing the technologies of both rules under the corresponding timeframes are economically achievable according to the Agency's IPM modeling, discussed further in section VII.F of this preamble. Furthermore, the EPA disagrees with comments suggesting it cannot revisit an ELG for seven years. The EPA has revisited many final ELG rules within this time frame, either as the result of a court's vacatur or remand, or as the result of an administrative petition. In fact, the same commenter arguing against the EPA's supplemental rulemaking here submitted administrative petitions for the EPA to reconsider the 2015 rule, and at that time found no procedural problem with the EPA revising a rule before seven years had elapsed.

The EPA views the retention of the 2020 BAT limitations for FGD wastewater and BA wastewater in the interim as in keeping with the technology-forcing nature of the CWA and essential for meeting the statutory requirement that BAT result in reasonable further progress toward the CWA's goal of zero discharge of pollutants. *See Nat. Res. Def. Council* v. *EPA,* 808 F.3d 556, 563–64 (2d Cir. 2015) (''Congress designed this standard to be technology-forcing, meaning it should force agencies and permit applicants to adopt technologies that achieve the greatest reductions in pollution.'') (citation omitted). Without these interim limitations, which have a

latest applicability date of December 31, 2025, plants could potentially have up to December 31, 2029 (the latest applicability for the zero-discharge requirements in this final rule), before they are required to meet limitations beyond the 1982 limitations based on surface impoundments. The EPA never intended that, as part of this rulemaking to explore additional pollutant discharge reductions that this industry could achieve, plants could thereby avoid taking available and achievable steps toward discharge control in the interim. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1003–1004 (describing the 1982-era regulations as from a ''by-gone era'' in which limitations were based on the ''archaic'' technology of surface impoundments, ''which are essentially pits where wastewater sits, solids (sometimes) settle out, and toxins leach into groundwater.''). More information on implementation of the 2020 rule limitations as an interim step toward achievement of the new zero-discharge FGD wastewater limitations is available in section XIV.A of this preamble.

D. Additional Rationale for the Proposed PSES and PSNS

Before establishing PSES/PSNS for a pollutant, the EPA examines whether the pollutant ''passes through'' a POTW to WOTUS or interferes with the POTW operation or sludge disposal practices. In determining whether a pollutant passes through POTWs for these purposes, the EPA typically compares the percentage of a pollutant removed by well-operated POTWs performing secondary treatment to the percentage removed by the BAT/NSPS technology basis. A pollutant is determined to pass through POTWs when the median percentage removed nationwide by well-operated POTWs is less than the median percentage removed by the BAT/NSPS technology basis. The EPA establishes pretreatment standards for those pollutants regulated under BAT/NSPS that pass through POTWs.

The EPA received comments that it should update this analysis to include more recent POTW pollutant removal data. Specifically, one commenter pointed to more recent analyses that POTWs remove 45 percent of arsenic and 60 percent of mercury. This comment also faulted the EPA for summarily finding that pollutants treated by a zero-discharge system would pass through a POTW since the POTW does not achieve 100 percent removals of these pollutants.

After considering these comments, the EPA finds that the 2015 rule pass-through analyses of these same technologies is still representative of current pollutant behavior. Specifically, the EPA is continuing to rely on the pass-through analyses as the basis of the limitations and standards in the 2015 rule as the Agency did in the 2020 rule. This analysis found that POTWs do not significantly remove mercury and arsenic in several wastewaters. Contrary to commenters' assertions that new data show some significantly improving removals of these pollutants, the EPA notes that table 10–1 of the 2015 TDD shows median arsenic removals of 65.8 percent and median mercury removals of 90.2 percent, higher removals than the new removal data cited by the commenters. Thus, because the EPA considered pass-through using higher pollutant removals, the EPA's findings would not change substituting the new pollutant removal data. With respect to zero discharge, the EPA is establishing zero-discharge limitations for three wastestreams in this rule. As in the 2015 rule, the EPA did not conduct its traditional pass-through analysis for wastestreams with zero-discharge limitations or standards. Zero-discharge limitations and standards achieve 100 percent removal of pollutants, including salts like boron and bromide which are not treated at all by the typical POTW treatment system.[159] Therefore, the EPA concludes that all pollutants in those wastestreams treated by the zero-discharge technologies would otherwise pass through the POTW absent application of the zero discharge technologies that form the BAT bases for FGD wastewater, BA transport water, and CRL.

PSES. After considering public comments and the record in light of the relevant CWA statutory factors, the EPA is establishing PSES for indirect discharges based on the technologies described in Option B. EPA is establishing Option B technologies as the bases for PSES for the same reasons that it is finalizing the Option B technologies as the bases for BAT for direct dischargers. The EPA's analysis shows that, for both direct and indirect dischargers, the final rule technologies are available and economically achievable, and they have acceptable non-water quality environmental impacts, including energy requirements (*see* sections VIII and X). For the final rule, the EPA is not selecting other technology bases for PSES for the same reasons that it is not finalizing other technology bases for BAT.

Furthermore, the EPA reaches the same conclusions for the same reasons discussed in section VII.C of this preamble with respect to several subcategories. EPA finds that retention of differentiated PSES for EGUs permanently ceasing coal combustion by 2028 are warranted. The EPA also finds establishing two new subcategories with differentiated PSES for EGUs permanently ceasing coal combustion by 2034 and legacy wastewater discharged from surface impoundments commencing closure after July 8, 2024, is warranted. In contrast, the EPA is not establishing a subcategory with differentiated PSES for discharges of unmanaged CRL because that subcategory is only intended to address CRL discharges that are found by a permitting authority to be the functional equivalent of a *direct* discharge to WOTUS or that are *direct* discharges of CRL to a WOTUS that result from the capture and pumping to the surface of CRL that has leached from a waste management unit into the subsurface and mixed with groundwater. Given the high volumes associated with operations that might capture and pump to the surface CRL that has leached from a waste management unit into the subsurface, the EPA does not expect facilities to find it a cost-feasible alternative to send such volumes to a POTW.

With respect to the low utilization subcategory, the EPA is eliminating the PSES subcategory for LUEGUs, as it does for direct dischargers, after further considering specific facts about the universe of plants that would potentially qualify for this subcategory. The EPA is only aware of one indirect discharger that has filed a NOPP to potentially avail itself of this subcategory, the Whitewater Valley Station; the EPA received no further comments indicating other indirect dischargers that planned to make use of the 2020 LUEGU subcategory. Whitewater Valley Station consists of two EGUs (Coal Boiler #1 and Coal Boiler #2). Coal Boiler #1 has a nameplate capacity of 35 MW, and it had 2019 and 2020 CURs of 5 percent and 3.67 percent, respectively. Coal Boiler #2 has a nameplate capacity of 65 MW, and it had 2019 and 2020 CURs of 5.5 percent and 5.1 percent, respectively. On its website, IMPA states that the station ''has been utilized by IMPA during peak load periods during the hot summer months and cold winter months.'' [160] This utilization

[159] The commenter has, in fact, historically sent its FGD wastewater to a POTW, thereby diluting the wastewater to the extent that it can meet a water quality-based effluent limitation for boron.

[160] *See www.impa.com/about-impa/generation-resources/giant-tcr.*

profile was confirmed by IMPA's comments on the 2023 proposed rule. At proposal, the EPA noted that Coal Boiler #1 is small enough to avail itself of the 2015 rule subcategory for small EGUs (*i.e.,* less than or equal to 50 MW nameplate capacity). While IMPA agreed, it also conveyed in its comments that it may not be able to increase the utilization of this small EGU without changes to its permits, and furthermore that this would not make up for any loss of operation of Coal Boiler #2 since both EGUs perform winter and summer peaking operations in tandem.

IMPA also clarified in its comments that the ash handling system it employs to comply with the CCR rule has not resulted in the elimination of its BA transport water discharges. The system includes dewatering bins followed by the addition of flocculant and coagulant to facilitate particulate removals in geotubes. Remaining wastewater is then sent to four polishing surface impoundments that are not designed to hold an accumulation of CCR, and thus not subject to the CCR rule, before the wastewater is sent to the POTW. While IMPA also provided concentration data from its BA transport water, none of this information demonstrated removals of pollutants to a degree that would change the results of the pass-through analysis from the 2015 rule.

Finally, IMPA provided comments describing the costs of potential BA transport water modifications, the impacts to the local community, and the potential for the facility to continue to support reliability.[161] In the comments regarding reliability, IMPA appeared to suggest that the facility would be operating until 2032. IMPA and the EPA had a follow-up conversation to discuss these comments and the EPA confirmed that, in the absence of outside factors, the facility is expecting to cease operations in 2032.

After considering the comments and information in the record, the EPA is eliminating the LUEGU subcategory for indirect dischargers as unnecessary and not supported by the factors relied on in 2020. With respect to FGD wastewater under the LUEGU subcategory, no NOPPs were filed from indirect dischargers requesting this subcategory for this wastestream. Thus, continued existence of this subcategory is unnecessary. With respect to BA transport water, EPA notes that, under the final rule's subcategory for EGUs permanently ceasing coal combustion by 2034, the one facility with indirect discharges to a POTW known to be interested in using the 2020 LUEGU subcategory would be able to continue to operate under the BA transport water PSES of the 2020 rule and retire in 2032 as planned without incurring any additional treatment costs and without creating an energy reliability concern. Thus, the LUEGU subcategory is no longer supported by the factors the EPA cited in the 2020 rule, nor any other factors.

PSNS. The EPA selects zero-discharge systems as the bases for the CRL PSNS for the same reasons that EPA selects these systems as the bases for the CRL NSPS (see section VII.B.3 of this preamble). The EPA's record demonstrates that zero-discharge systems are available and demonstrated, do not pose a barrier to entry, and have acceptable non-water quality environmental impacts, including energy requirements (see sections VII.G and X of this preamble). The EPA rejected other options for CRL PSNS for the same reasons that it rejected other options for CRL NSPS. And, as with the final CRL PSES, the EPA concludes that the final CRL PSNS prevent pass through of pollutants from POTWs into receiving streams and help control contamination of POTW sludge.

E. Availability Timing of New Requirements

Where BAT limitations in the 2015 and 2020 rules are more stringent than previously established BPT limitations, those BAT limitations do not apply until a date determined by the permitting authority that is ''as soon as possible'' after considering four factors. Depending on the particular wastewater, the 2015 and 2020 rules also established a ''no later than'' date of December 31, 2023, or December 31, 2025, for reasons discussed in the record of those rules, including that, without such a date, implementation could be substantially delayed, and a firm ''no later than'' date creates a more level playing field across the industry.

As part of the consideration of the technological availability and economic achievability of the new BAT limitations in this regulation, the EPA considered the magnitude and complexity of process changes and new equipment installations that would be required for plants to meet the final rule's new, more stringent limitations and standards. Specifically, the EPA considered timeframes that enable many plants to raise needed capital, plan and design systems, procure equipment, and construct and test systems. The EPA also considered the timeframes needed for appropriate consideration of any plant changes being made in response to other Agency rules affecting the steam electric power generating industry. The EPA understands that some plants may have already installed, or are now installing, technologies that could comply with the rule's limitations. Therefore, EPA finds that the earliest date some plants can achieve compliance with these new limitations would be July 8, 2024. Where this is not the case, nothing in this rule would preclude a permitting authority from establishing a later date, up to the ''no later than'' date, after considering the four specific factors in 40 CFR 423.11(t).[162]

With respect to the latest compliance dates, the EPA collected updated information on the technical availability of the BAT technology bases. Information in EPA's rulemaking record indicates that a typical timeframe to raise capital, plan and design systems (including any necessary pilot testing), procure equipment, and construct and test systems falls well within the existing five-year permit cycle.[163] Furthermore, the chemical precipitation and zero-discharge BAT technologies here do not implicate the same industrywide competition over a small number of biological treatment vendors that the 2020 rule implicated. The EPA notes that while plants may not need about five years to comply with the final limitations, the ''no later than'' date creates an outer boundary beyond which no discharger may seek additional time and creates a level playing field regarding the latest date. Therefore, the EPA is finalizing the requirement that the new limitations for FGD wastewater, BA transport water, and CRL be achieved ''no later than'' December 31, 2029.

The EPA received comments that these ''no later than'' dates should be shortened or lengthened. Comments suggesting shortening these timeframes focused on record information

[161] While the EPA received comments from other parties about the elimination of this PSES subcategory, only IMPA provided site-specific information that was potentially relevant to the EPA's discussion here. For further discussion of comments, see *Response to Public Comments for Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, April 2024* (SE11794).

[162] These factors are: (1) time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final rule; (2) changes being made or planned at the plant in response to GHG regulations for new or existing fossil fuel-fired power plants under the CAA, as well as regulations for the disposal of coal combustion residuals under subtitle D of RCRA; (3) for FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment; and (4) other factors as appropriate. *See* 40 CFR 423.11(t).

[163] *See* FGD and Bottom Ash Implementation Timing (DCN SE08480).

describing that individual facilities can install certain technologies in timeframes shorter than out to 2029. EPA declines to establish ''no later than'' dates shorter than one permit cycle from the final rule. Some permits may not be renewed and able to incorporate the new limitations until 2029, and this later date creates an even playing field for the industrial category. In contrast, commenters suggesting lengthening these timeframes did not provide specific data that demonstrate a legitimate need for a longer timeframe. In the absence of data demonstrating different timelines are necessary or appropriate (*e.g.,* engineering dependency charts), the EPA cannot justify timeframes longer than those in the Agency's current record.

For the new subcategory for EGUs permanently ceasing coal combustion by 2034, the EPA is finalizing different availability timing for the BAT limitations applicable to CRL discharged after cessation of coal combustion. Since CRL was not covered by the 2020 permanent cessation of coal subcategory, plants with EGUs retiring both before and after 2028 may wish to avail themselves of the CRL limitations applicable to the subcategory for EGUs permanently ceasing coal combustion by 2034. Furthermore, as discussed in section VII.C.4 of this preamble, the new subcategory for EGUs permanently ceasing coal combustion by 2034 takes into account the changes expected to occur in CRL flow after closure of the WMU, the timing of which depends on, but is not the same as, the date the EGU will cease coal combustion. To facilitate administration, the EPA is adopting the same ''as soon as possible'' applicability timing framework as used for other limitations in this rule. Thus, the BAT limitations for mercury and arsenic in CRL discharges from this subcategory must be met as soon as possible beginning 120 days after permanent cessation of coal combustion. Since the subcategory allows for permanent cessation of coal combustion by December 31, 2034, with an additional 120 days allowed for the discharge of FGD wastewater, the Agency is adopting an April 30, 2035 ''no later than'' date for meeting BAT limitations for discharges of CRL from this subcategory.[164] Thus, while a permitting authority must establish availability timing that is ''as soon as possible,'' nothing in this rule would preclude a permitting authority from establishing a later date, up to the ''no later than'' date, after considering the four specific factors in 40 CFR 423.11(t). For PSES in this subcategory the statute does not allow for flexible availability timing and so here, to provide the same flexibility, the Agency is adopting tiered limitations with the second tier applying no later than April 30, 2035.

For the discharge of legacy wastewater, the EPA is not establishing the same ''no later than'' date framework as the other wastewaters. Instead, the limitations for legacy wastewater are simply effective on July 8, 2024. For legacy wastewater generally, this makes sense because the BAT limitations are based on a permitting authority's BPJ, and permitting authorities may consider the availability timing of technologies to a particular plant as part of its BAT determination. For legacy wastewater in the new subcategory described in section VII.C.6 of this preamble, this will have no impact because, as of the effective date of this rule, these surface impoundments will not have triggered the requirements under the CCR regulations to cease receipt of waste and commence closure. Furthermore, allowing for up to five years before the limitations' ''no later than'' date could provide time for circumvention of these limitations where a plant quickly drains its surface impoundment under the existing case-by-case approach.

As with the new BAT effluent limitations, in considering the availability and achievability of the new PSES, the EPA concluded that existing indirect dischargers need some time to achieve the final standards, in part to avoid forced outages. While the BAT limitations apply on a date determined by the permitting authority that is as soon as possible beginning on the effective date of the final rule, but no later than December 31, 2029, under CWA section 307(b)(1), pretreatment standards shall specify a time for compliance not to exceed three years from the date of promulgation, so the EPA cannot establish a longer implementation period. Moreover, unlike requirements on direct discharges, requirements on indirect discharges are not implemented through NPDES permits. Nevertheless, the EPA finds that all existing indirect dischargers can meet the standards within three years of promulgation as discussed below.

At proposal, the EPA projected that there would be no remaining indirect dischargers of FGD wastewater. In response to this finding, City Water, Light and Power (CWLP) filed comments indicating that it retains the option of either sending its treated FGD wastewater to the local POTW, or directly discharging. The EPA takes CWLP at its word that it will continue to be an indirect discharger at least some of the time. Nevertheless, the EPA estimates that it would take a single plant 18 to 28 months to achieve zero discharge for both FGD wastewater and CRL. Similarly, with respect to BA transport water, the EPA estimates that a closed-loop system can achieve zero discharge within 35 months, and substantially sooner if a high recycle rate system is already operating.[165] Finally, with respect to legacy wastewater and CRL generated after permanent cessation of coal combustion, the EPA estimates the chemical precipitation systems can achieve the mercury and arsenic limitations within 22 months.[166] Thus, the final PSES are available 3 years after publication of the final rule. Further discussion of availability timing can be found in section XIVB.1 of this preamble.

F. Economic Achievability

Under the CWA, BAT limitations must be economically achievable. Courts have interpreted the economic achievability requirement as a test of whether the regulations can be ''reasonably borne'' by the industry as a whole. *Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d at 262; *BP Exploration & Oil* v. *EPA,* 66 F.3d at 799–800; *see also Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1006; *Nat'l Wildlife Fed'n* v. *EPA,* 286 F.3d 554, 570 (D.C. Cir. 2002); *CPC Int'l Inc.* v. *Train,* 540 F.2d 1329, 1341–42 (8th Cir. 1976), *cert. denied,* 430 U.S. 966 (1977). ''Congress clearly understood that achieving the CWA's goal of eliminating all discharges would cause 'some disruption in our economy,' including plant closures and job losses.'' *Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d at 252 (citations omitted).

At proposal, the EPA found that the rule was economically achievable, but solicited comment on whether and how to include the impacts of the IRA for the final rule analysis. The EPA received comments recommending modifications to its use of IPM. Specifically, some commenters recommended including the impacts of the IRA in the baseline, while other comments disagreed that the EPA should include the IRA impacts, with the latter commenters suggesting that any results with the IRA

[164] Where EGUs are ceasing coal combustion near the end of this timeframe, or where closure of a WMU is lengthy such that it extends past this latest date, it is possible that a facility may not be able to fully take advantage of this flexibility for all of its WMUs.

[165] DCN SE08480.

[166] The EPA expects this timing to be similar to a chemical precipitation installation for FGD wastewater, DCN SE10289.

included would be speculative and uncertain. The EPA also received comments that its findings should consider the joint impact of multiple regulations on this industry.

The EPA acknowledges these comments. The EPA used IPM to perform cost and economic impact assessments, using a baseline that reflects impacts from the IRA and final environmental regulations that were published before this rule was signed (*see* RIA).[167] As explained in detail in section VIII of this preamble, the IPM baseline used for this analysis includes the impacts of the IRA and several other final power sector regulations published before this rule. This is consistent with OMB Circular A–4 and EPA's *Guidelines for Preparing Economic Analysis.*[168] The EPA did not, however, include all the regulations some comments suggested. For example, two CAA rules, the MATS and section 111 rules, are being issued contemporaneously with this ELG and none of these rules includes the others in the baseline of the primary IPM analysis. This too is consistent with OMB guidelines and established EPA practice.

EPA's analysis for the final BAT limitations and PSES demonstrates that they are economically achievable for the steam electric industry, as required by CWA section 301(b)(2)(A). For the final rule, the model projected very small additional effects on the electricity market, on both a national and regional sub-market basis. Based on the results of these analyses, the EPA estimated that the final rule requirements would result in a net reduction of 5,782 MW in steam electric generating capacity as of the model year 2035, reflecting full compliance by all plants. This capacity reduction corresponds to a net effect of approximately five early plant retirements.[169] These IPM results support the EPA's conclusion that the final rule is economically achievable.

Furthermore, before the IPM analysis, the EPA also performed a cost-to-revenue screening analysis which included costs to wastestreams not tied to ongoing electric generation (*i.e.,* costs which would not change operational decisions in IPM). Specifically, this analysis included the upper bound and lower bound costs for treating unmanaged CRL as well as the costs of treating legacy wastewater discharged from surface impoundments commencing closure after July 8, 2024. For further discussion of these costs, see section VIII.A of this preamble. The screening-level assessment of economic impacts showed a greater potential for impacts with 13 to 17 parent entities incurring annualized costs representing one percent or more of their revenues, including 6 to 9 parent entities that would incur costs representing more than three percent of revenue. Since the EPA estimates that there are between 220 and 391 parent entities, this means that between three and eight percent of parent entities would incur costs representing one percent or more of their revenues and a subset of between two and four percent of parent entities would incur costs representing more than three percent of revenue. However, as noted in the RIA, these results are based on the conservative assumption that zero costs are passed on to consumers and represent a worst-case scenario from the plant owners' perspective. The combination of the screening analysis (including unmanaged CRL costs) and the IPM market-level results (excluding unmanaged CRL costs) supports the EPA's conclusion that the final rule is economically achievable.

Other considerations also support the EPA's findings on economic achievability. While EPA properly excluded from its main analysis regulations that are being issued contemporaneously with this rule and that were not published before this rule was signed, the Agency conducted a supplemental analysis to evaluate the cumulative effect of multiple rules affecting the electric power sector. This multi-rule modeling includes this final rule, CAA sections 111(d) and 111(b) EGU rules, and MATS as a combined policy scenario, and includes the EPA vehicle rules (LDV, MDV and HDV) in the baseline (*i.e.,* relevant EPA rules). As such, the results of this modeling cannot be used to show the individual effect of this final rule and are not a substitute for the rule-specific modeling EPA conducted to determine economic achievability of the final rule. However, the multi-rule modeling does clearly illustrate that the cumulative effect of these rules in terms of reduction in steam electric generating capacity is less than the sum of each of these rules individually. This means that, considering the rules together, the affected universe of EGUs with significant mitigation responsibilities under the EPA rules that make up the policy case is overlapping, not purely additive, as it largely reflects the same segment of the grid's generation portfolio. In other words, if the same EGU at baseline that has new regulatory requirements for both its air and water wastestreams chooses to retire rather than adopting control technologies, it would not do so twice, and so the generation lost from that EGU would only need to be replaced once. Hence, simply adding the independently modeled costs of each of the rules, which include effects associated with coal-fired EGU retirements attributable to each rule, would be inappropriate, as these effects are not additive. The sensitivity analysis bears this out over the time periods of relevance to the ELG.[170]

In terms of reductions in coal-fired generating capacity and coal plant closures, affected EGUs are expected to undertake investment decisions to comply with multiple rules simultaneously, as seen in the sensitivity analysis for the combined policy scenario. For example, EGUs that decide to invest in CCS in relevant years may also decide to invest in a dry-handling system, depending on the operational need of the unit. In this case, the costs of CCS and a dry-handling system may be summed. However, if an EGU decides to retire, then the costs associated with the retirement decision would occur only once. For the reasons discussed above, had the Agency done an IPM analysis of ELG impacts in which the other relevant EPA rules were in the baseline, EPA expects that the results of such an analysis would likely show comparable or fewer impacts attributable to the ELG than projected in EPA's main analysis.[171] Thus, nothing in the multi-rule modeling suggests EPA's conclusion that the final ELG rule is economically achievable would be meaningfully different, particularly where courts have upheld EPA's BAT regulations as economically achievable even under circumstances of much greater industry-wide economic impact than projected here. *See Chem. Mfrs. Ass'n* v. *EPA,* 870 F.2d at 252 n.337

[167] IPM is a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. See section VIII of this preamble for additional discussion.

[168] Available online at: *https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses-2016.*

[169] Given the design of IPM, unit-level and thereby plant-level projections are presented as an indicator of overall regulatory impact rather than a precise prediction of future unit-level or plant-specific compliance actions. The projected net plant closure occurs at a plant whose only steam electric EGU had a capacity utilization of only six percent in the baseline.

[170] See *IPM Sensitivity Runs Memo* (SE11829) for further details.

[171] The multi-rule run also confirms that resource adequacy is maintained, even taking into account the collective impact of the various EPA rules discussed here. See *Resource Adequacy Analysis: Vehicle Rules, 111 EGU rule, ELG, and MATS Technical MEMO* (SE11830).

(reviewing cases in which courts have upheld EPA's regulations that projected up to 50 percent closure rates).

Finally, the EPA notes that coal-fired power plants with the wastestreams subject to this final rule are only a fraction of all coal-fired power plants, which are only a fraction of all steam electric power plants subject to part 423. The combination of the screening analysis (including unmanaged CRL and legacy wastewater costs), the IPM market-level results (excluding unmanaged CRL and legacy wastewater costs), and the other considerations in this paragraph support the EPA's conclusion that the rule is economically achievable.

G. Non-Water Quality Environmental Impacts

For the 2023 proposed rule, the EPA assessed non-water quality environmental impacts, including energy requirements, air impacts, solid waste impacts, and changes in water use and found them to be acceptable. The EPA reevaluated these impacts in light of the changed industry profile and public comments, as well as the requirements of the final rule. Based on the results of these analyses, the EPA determines that the final rule has acceptable non-water quality environmental impacts. See additional information in section 7 of the Supplemental TDD, as well as section X of this preamble.

H. Impacts on Residential Electricity Prices and Communities With Environmental Justice Concerns

The EPA presents the effects of the final rule on consumers as part of the RIA. While the CWA section 304(b)'s ''consideration'' factors do not require these details, the EPA presents them for informational purposes. If all annualized compliance costs were passed on to residential consumers of electricity instead of being borne by the operators and owners of power plants (a conservative assumption), the average yearly electricity bill increase for a typical household would be $1.61 to $3.14 under the final rule, or a change of less than 0.1 percent relative to the baseline. For further information see section 7 of the RIA.

The EPA also presents the effect of the final rule on communities with environmental justice concerns under Executive Order 14096. As explained in sections XIII and XV.J, using demographic data on who resides closest to steam electric power plant discharges, who fishes in downstream waterbodies, and who consumes drinking water from downstream drinking water treatment plants, the EPA concludes that, although benefits are likely to accrue to all members of the affected public, communities with environmental justice concerns will experience health and environmental benefits more than the general population from the reductions in discharges associated with the final rule due to their disproportionate exposure.

VIII. Costs, Economic Achievability, and Other Economic Impacts

The EPA evaluated the costs and associated impacts of the three main final regulatory options on existing EGUs at steam electric power plants. The Agency analyzed these costs within the context of existing environmental regulations, market conditions, and other trends that have affected steam electric power plant profitability and generation, as described in section V.B of this preamble. This section provides an overview of the methodology the EPA used to assess the costs and the economic impacts and summarizes the results of these analyses. The methodology is largely the same as for the proposed rule analysis, but with updates to reflect more recent data and comments the EPA received on the proposal. See the RIA in the docket for additional detail.

In developing ELGs, and as required by CWA section 301(b)(2)(A), the EPA evaluates the economic achievability of regulatory options to assess the impacts of applying the limitations and standards to the industry as a whole, which typically includes an assessment of incremental plant closures attributable to a regulatory option. As described in more detail below, this supplemental ELG is expected to result in incremental costs when compared to baseline. Like the prior analysis of the 2015 and 2020 rules and the 2023 proposal, the cost and economic impact analysis for this final rule focuses on understanding the magnitude and distribution of compliance costs across the industry and the broader market impacts. The EPA used indicators to assess the impacts of the three regulatory options on the whole steam electric power generating industry. These indicators are consistent with those used to assess the economic achievability of the 2015 and 2020 rules and the 2023 proposal. As was done at proposal, the EPA compared the values to a baseline that reflects implementation of existing environmental regulations (as of this final rule), including the 2020 rule and the effects of the IRA of 2022, but does not include the effects of regulations discussed in section IV.E of this preamble that had not been published at the time of signature of this final rule. As such, the baseline appropriately includes the costs of achieving the 2020 rule limitations and standards, and the policy cases show the impacts resulting from potential changes to the existing 2020 limitations and standards. More specifically, the EPA considered the total cost to the industry and the change in the number and capacity of specific EGUs and plants expected to close under the final rule (Option B) compared to the baseline. The EPA also analyzed the ratio of compliance costs to revenue to see how the three main regulatory options affect how many plants (and their owning entities) exceed thresholds indicating potential financial strain. In addition to the analyses supporting the economic achievability of the regulatory options, the EPA conducted other analyses to (1) characterize other potential impacts of the regulatory options (*e.g.,* on electricity rates) and (2) meet the requirements of Executive Orders or other statutes (*e.g.,* Executive Order 12866, Regulatory Flexibility Act, Unfunded Mandates Reform Act).

A. Plant-Specific and Industry Total Costs

The EPA estimated plant-specific costs to control FGD wastewater, BA transport water, CRL, and legacy wastewater discharges at existing EGUs at steam electric power plants to which the ELGs apply.

The EPA assessed the operations and treatment system components currently in place at each unit (or expected to be in place because of other existing regulations, including the 2020 ELG rule), identified equipment and process changes that plants would likely make under each of the three regulatory options presented in table VII–1 of this preamble, considering the subcategory applicable to each EGU, and estimated the capital and O&M costs to implement those changes. As explained in the TDD, the baseline also accounts for additional announced unit retirements, conversions, and relevant operational changes that have occurred since the EPA promulgated the 2020 rule. Following the same methodology used for the 2015 and 2020 rules and the 2023 proposal analyses, when estimating the annualized industry compliance costs, the EPA used a private rate of capital to annualize one-time costs and costs recurring a nonannual basis. For this analysis, this rate is 3.76 percent and represents estimated weighted average cost of capital for the industry. For capital costs and initial one-time costs, the EPA used

a 20-year amortization period. For O&M costs incurred at intervals greater than one year, the EPA used the interval as the annualization period (*e.g.,* five years, 10 years). The EPA added annualized capital, initial one-time costs, and the nonannual portion of O&M costs to annual O&M costs to derive total annualized plant costs. The EPA estimated after-tax costs based on the type of entity owning each plant. The EPA then calculated total industry costs by summing plant-specific annualized costs.

The EPA proposed that membrane filtration was BAT for FGD wastewater; therefore the Agency continued to rely primarily on the costs of membrane filtration to evaluate economic achievability at proposal while analyzing costs of SDEs and thermal evaporation systems using sensitivity analyses. Comments supportive of zero discharge suggested that sometimes thermal evaporation systems were less costly than membrane filtration systems and that these systems can achieve zero discharge alone or in combination. Other commenters suggested that the EPA's cost estimates were too low. Specifically, commenters suggested that the EPA did not properly reflect the costs of FA diversion to a landfill as part of the proposal's membrane filtration costs.

The EPA has updated its cost estimates to more accurately reflect the costs of FA used for brine encapsulation. As a result of these updates, the EPA estimates that membrane filtration is no longer the least costly FGD treatment technology nationwide.

Furthermore, because the final rule identifies the BAT technology basis for FGD wastewater as membrane filtration, SDEs, and thermal evaporation systems alone or in combination, the EPA performed a least-cost analysis to determine which technology each plant would select. While the EPA costed all three technologies, the cost estimates for thermal technologies contain CBI and cannot be released publicly.[172] To increase transparency of this final rule, the EPA ran an alternative set of costs selecting the least-cost technology between only membrane filtration and SDEs. The EPA found that only six plants would select thermal evaporation systems as the lowest cost option when considering all three technologies. Moreover, when comparing the least-cost analysis among the three technologies to the least-cost analysis with only membrane filtration and SDEs, the EPA found that the overall costs associated with the latter exceed the former by only five percent. Since the non-CBI costs do not substantially differ from the CBI costs, the EPA ran these non-CBI costs through IPM so that model's inputs and outputs could also be made public.

With respect to BA transport water, the 2020 rule record never demonstrated that a full 10 percent purge at all facilities was a realistic costing assumption. The primary basis for the 2020 rule purge allowance was a 2016 report from EPRI that involved continuous purges, the majority of which were well under one percent. Thus, in the 2020 rule record, the EPA presented a sensitivity analysis with costs for a two percent purge treatment, which better reflect the handful of facilities for which the EPA has record evidence of a purge.

At proposal, the EPA retained this dual costing approach. Based on IPM modeling results, including the 10 percent purge treatment cost estimates, the EPA proposed to find that dry-handling or closed-loop systems are economically achievable. The EPA received comments suggesting that a 10 percent purge is not realistic of the potential purge needs of facilities. EPA agrees that the record reflects very few facilities with demonstrated purge needs, and that these were all two percent or less. Thus, the Agency has now adopted the more realistic two percent purge treatment cost estimate as its primary analysis but has retained the 10 percent purge treatment costs as a sensitivity analysis.[173]

With respect to CRL, the EPA proposed to establish limitations based on chemical precipitation systems but estimated the costs of alternative zero-discharge systems for treating CRL in a separate memorandum. Some commenters asked the EPA to repropose CRL limitations since these analyses were not presented as part of the main regulatory options. Commenters also presented various reasons why they believed that the EPA's cost estimates were too low. Specifically, commenters suggested that the EPA did not properly reflect the costs of fly ash diversion to a landfill as part of the proposal's membrane filtration costs.

The EPA disagrees with commenters that it should repropose CRL limitations because costs and pollutant loadings of additional technologies were estimated in a separate document. The Agency provided commenters with a fair opportunity to present their views on the contents of the final rule, which is all that is required to satisfy notice and comment requirements. *BASF Wyandotte Corp.* v. *Costle,* 598 F.2d 637, 641–644 (1st Cir. 1979) (rejecting notice and comment objections to a final ELG rule based on changes from proposal). The EPA has also updated its cost estimates to reflect more accurate costs of using FA for brine encapsulation as was done for FGD wastewater in section VII.B.1 of this preamble.

With respect to unmanaged CRL, the proposed rule included a bounding sensitivity analysis with costs for every facility and every unlined landfill and surface impoundment (WMU) to treat their unmanaged CRL either with chemical precipitation or SDEs. These bounding analyses were presented as a conservative estimate to demonstrate the potential universe of discharges of unmanaged CRL and potential costs. Some commenters stated their view that the EPA had not sufficiently evaluated unmanaged CRL and argued that the EPA should re-propose CRL limits after conducting a more accurate costing analysis. The EPA also received comments disagreeing with two misunderstandings of the Agency's proposed application of the rule to unmanaged CRL, with commenters believing either all or none of the facilities in the Agency's analyses were covered. One commenter further suggested that the EPA should include additional WMUs under the new CCR proposed rule (88 FR 31982).

The EPA disagrees with commenters that it did not sufficiently evaluate unmanaged CRL and that CRL limits should be re-proposed. The proposed rule gave commenters notice of the basic engineering cost and economic screening approaches that the Agency applied in evaluating discharges of unmanaged CRL for the final rule, as those approaches have not changed. Furthermore, at proposal, the EPA analysis included the broadest set of potential facilities and WMUs estimated to be potentially subject to these limitations to ensure that the public was given fair notice of how the final rule could apply, even in cases where such an application might be highly unlikely. The EPA disagrees with commenters that making this assumption for the purposes of a bounding analysis had any implications as to whether a permitting authority would ultimately find the existence of a point source with

[172] Standard thermal evaporation system costs are analyzed in DCN SE11694 but not included in this least cost analysis because portions of those costs are being treated as CBI pursuant to claims made by vendors under the EPA's CBI regulations.

[173] This primary use of the two percent numbers is also more reasonable when considering the definitional change whereby necessary discharges from storm events are not considered BA transport water, and thus would not require any additional purge or purge treatment.

a functional equivalent direct discharge to a WOTUS at any given WMU.

For the final rule, to better reflect on-the-ground reality, and in response to public comment, the EPA has refined the bounding analyses from proposal to remove the WMUs least likely to incur costs under this final rule. The EPA began by compiling groundwater monitoring information from unlined WMUs reported under the CCR regulations. This information consisted of detection monitoring data, assessment monitoring data, statistical analyses, and other narrative discussion in the groundwater monitoring reports. WMUs which are still in detection monitoring, and where there is either no statistically significant increase (SSI) of specified parameters [174] above the groundwater background, or an increase that is not attributable to the WMU, are the least likely to be sources of pollutants and therefore also the least likely to potentially incur treatment costs under the rule. Thus, the EPA excluded these units from its revised bounding analysis.

In addition to the updated bounding analysis, for the final rule, also in response to public comments, the EPA now presents a range of more likely costs consisting of a revised upper bound and revised lower bound analysis. These lower and upper bounds provide a likely more accurate range of cost estimates and other impacts for treating unmanaged CRL. The revised upper bound estimate probabilistically considers three separate scenarios, described in the next paragraph. The revised lower bound estimate probabilistically considers an additional four scenarios, also described below. Together, the resulting range represents a reasonable range of nationwide costs of treatment for unmanaged CRL, but as discussed in the following paragraphs, it could overestimate costs at some facilities and underestimate costs at others.

The revised upper bound cost estimate uses proxies for the factors that make unmanaged CRL more likely to be subject to the limitations in the final rule, and therefore more likely to incur costs. The first scenario the EPA modeled was one in which unmanaged CRL treatment costs are assigned only to each plant's WMU closest to a surface waterbody. The Supreme Court in *County of Maui* recognized the importance of distance in determining whether a discharge might fall within the CWA's jurisdiction. *County of Maui* v. *Hawaii Wildlife Fund,* 590 U.S. at 184. For any given facility, for purposes of this cost estimate, the EPA assumes that the unlined WMU that is most likely to have unmanaged CRL subject to this rule's limitations is the unlined WMU nearest a surface waterbody. In selecting the nearest such WMU for the purposes of analysis, the EPA is not making any findings that these unmanaged CRL discharges would be subject to the final rule requirements or that discharges from other WMUs would not be. In reality, WMUs further from a surface waterbody could be found to be point sources with FEDDs of CRL to a WOTUS which are subject to CWA permitting. In addition, any of the closest WMUs modeled here may be found not to be point sources with FEDDs of CRL and thus subject to CWA permitting. Nevertheless, the EPA finds that it is reasonable to assume that the closest WMUs are more likely to incur costs under this final rule.

The other two scenarios the EPA modeled focused not on distance, but on which WMUs are more likely to be a source of pollutants. For these WMUs, the Agency estimated costs of chemical precipitation treatment at both the WMU level and at the facility level. As discussed in the preceding paragraphs, the EPA's updated bounding analysis already removed those WMUs with less probability of incurring costs for unmanaged CRL treatment due to the absence of a WMU-caused SSI in detection monitoring pollutants (*e.g.,* TDS). Just because a facility finds an SSI for a detection monitoring parameter does not indicate that it will incur costs under this final rule. This final rule imposes mercury and arsenic limitations based on chemical precipitation, a treatment system that does not treat all pollutants which might be found in TDS and other detection monitoring parameters. Instead, the EPA notes that nearly all of the assessment monitoring pollutants in appendix IV to part 257 are pollutants treated by chemical precipitation. The EPA finds that WMUs that are the source for an SSI of one or more appendix IV pollutants, and thus trigger corrective action under the CCR regulations, are the most likely to incur chemical precipitation-related costs under this final rule. This is so for two reasons.

First, there is the possibility that these facilities could, in the future, select a pump-and-treat remedy under the corrective action requirements of the CCR regulation, which will be discharged. Any resulting direct discharge would need to comply with the limits in this rule. Second, where a pump-and-treat remedy is not selected, the EPA examined treatment of arsenic. Arsenic has historically been one of the most prevalent pollutants in CCR damage cases and under this final rule is also one of the two indicator pollutants monitored to demonstrate compliance with the BAT limitations for discharges of unmanaged CRL. While this regulation establishes technology-based limitations, the daily and monthly arsenic limitations being finalized are very close to, and bracket, the health-based arsenic standard in the CCR regulations.[175] Thus, for purposes of determining the facilities and WMUs most likely to incur costs with respect to unmanaged CRL, the EPA finds that focusing on arsenic is reasonable.

While the EPA believes that using WMUs that have triggered corrective action is a reasonable proxy for estimating WMUs most likely to incur costs associated with unmanaged CRL under this rule, EPA notes that here too, just because a facility is in corrective action for its groundwater contamination does not mean that the WMU at issue would necessarily be found to be a point source with a FEDD of CRL to a WOTUS. Thus, in some cases, these costs will be overestimated for specific facilities. At the same time, it may be possible that unmanaged CRL is subject to CWA permitting but does not trigger corrective action under the CCR regulations.

Due to the uncertainties surrounding future permitting authority findings regarding unmanaged CRL, the EPA probabilistically combined the three cost scenarios discussed above with equal weights: those involving (1) each plant's closest WMU, (2) cases of corrective action at the WMU level, and (3) cases of corrective action where surface impoundment flows are combined at the facility level. These modeling assumptions should not be interpreted as a finding that any specific site is subject to the unmanaged CRL limitations in the final rule. Rather, these assumptions should be considered as assisting in a reasonable estimation of costs nationwide, with actual site-specific costs under- or overestimated.

[174] Appendix III to Part 257—Constituents for Detection Monitoring includes TDS.

[175] The daily and monthly BAT limitations being established are 11 ug/L and 8 ug/L, respectively as compared to the maximum contaminant level of 10 ug/L, which is the trigger for corrective action under the CCR regulations.

The revised lower bound cost estimate uses proxies for the factors that make unmanaged CRL most likely to be subject to the limitations in the final rule, and therefore most likely to incur costs. Specifically, as of January 22, 2022, the EPA was aware of 67 WMUs at 38 facilities which had selected corrective action remedies that includes pumping and treating of groundwater now or in the future.[176] These data are summarized in table VIII–1 below.

Table VIII-1. CCR Corrective Action Remedies Selected by 2021

Unit/Facility	Count	Pump & Treat	GW Extraction/ Collection	Both	Pump & Treat %	Both %
Individual LFs	18	3	2	5	17%	28%
Individual Sis	49	11	6	17	22%	35%
Facilities w/LFs	16	3	2	5	19%	31%
Facilities w/Sis	26	2	4	6	8%	23%

* Notes: LF = landfill; SI = surface impoundment; Facility counts add to 42 rather than 38 because four facilities have both landfills and surface impoundments

While the statistics are based on a 2022 subset of the facilities that have selected corrective action remedies thus far or will select corrective action remedies in the future, this empirical data provides the best available information on which to base the fraction of WMUs or facilities that may ultimately select a remedy that generates a CRL wastestream that could potentially be discharged, and thus potentially incur treatment costs under the final rule. While some of these facilities selected a remedy that explicitly included pump-and-treat operations, others included other categories of groundwater extraction or collection that may or may not ultimately result in a discharge. The EPA probabilistically used four scenarios to account for the uncertainty in the likelihood of a discharge that would incur ELG compliance costs.

Two scenarios relied on the fraction of WMUs where such discharges were possible based on the remedy selected. Due to the number of WMUs at different facilities being unequal, the EPA also evaluated two scenarios that instead relied on the fraction of facilities with landfills and the fraction of facilities with surface impoundments where such discharges were possible. For each of these, a pair of estimates was generated assuming the fraction that would ultimately discharge subject to the ELG would include either only the pump-and-treat operations or, alternatively, both pump-and-treat operations and other remedies with groundwater collection or extraction that could potentially discharge in the future. For the two scenarios using the facility-based extrapolation, the EPA used the costs for facility-wide corrective action described as one scenario in the revised upper bound scenario in the preceding paragraphs. Finally, by treating each of these scenarios with an equal likelihood to occur, the revised lower bound estimate avoids attaching too much certainty to any individual estimate based on this data set.

The EPA notes that the revised upper bound analysis still represents a conservative estimate of the costs for unmanaged CRL. As facilities continue to implement the CCR regulations, landfills and surface impoundments continue to close and conduct corrective action. In some cases, closure may eliminate the continued source of pollutants (*e.g.,* WMUs which are clean closed) or may reduce the concentrations of pollutants, making treatment costs under this final ELG less likely. Furthermore, where corrective action is taken pursuant to the CCR regulations, it is possible that the corrective action selected would reduce the probability that the facility would incur costs under the final rule. This could be the result of installing impermeable or semi-permeable barriers, conducting *in-situ* treatment, or undergoing pump-and-treat operations where the water is returned to the ground rather than discharged. Even where unmanaged CRL in groundwater is pumped to the surface, some of that water may be reused within the plant or treated and returned to the ground. When considered against this backdrop, the revised upper bound costs estimated for unmanaged CRL can be considered a reasonable, conservative estimate for purposes of ensuring that these costs are considered and found to be economically achievable.

Similarly, the revised lower bound analysis still represents a likely underestimate of the costs of unmanaged CRL. Once regulations establishing a Federal CCR permit program are finalized, the EPA or state agencies may find that some previously selected corrective action remedies may not satisfy the corrective action requirements under the CCR regulations and, thus, a new remedy which does result in a discharge could be required. Furthermore, it may be possible that some unmanaged CRL satisfying the health-based requirements of the CCR regulations could still result in a FEDD of CRL into a WOTUS and, therefore, incur costs for complying with the ELG. For these reasons, the EPA believes the ultimate costs and economic impacts associated with unmanaged CRL are most likely to fall between the revised upper bound and revised lower bound estimates evaluated in the Agency's cost and economic analyses.

With respect to legacy wastewater, the EPA proposed to retain the existing case-by-case limitations but estimated the costs of alternative treatment systems for treating legacy wastewater in a separate memorandum at proposal. Some commenters asked the EPA to repropose legacy wastewater limitations since these analyses were not presented as part of the main regulatory options. The EPA disagrees with commenters for the same reasons presented in the CRL discussion immediately above. For the subcategory of surface impoundments continuing to operate after the effective

[176] EPA presents this dataset in DCN SE11501.

date of the rule, the EPA expects that many plants may only close and dewater their ponds after 2049, which is outside of the period of analysis (and thus, for the purposes of this analysis, would be zero). The Agency has also evaluated a worst-case scenario where all plants close and dewater their ponds soon after the final rule is effective (see RIA appendix C). These costing scenarios bound the potential costs of the final subcategory; however, the likely costs fall somewhere in between. While the EPA cannot know with certainty when a surface impoundment may be closed in the future, the Agency compiled data in the 2015 CCR rule record which revealed a median operating life of 40 years for a surface impoundment [177] and this 40-year life was used for estimating costs, benefits, and other impacts in *Regulatory Impact Analysis for EPA's 2015 Coal Combustion Residuals Final Rule.* To ensure that the costs of the final legacy wastewater subcategory were included in the Agency's main cost analyses, the Agency assumed that these costs would be incurred in 2044. This corresponds to 20 years after the effective date of the final rule (*i.e.,* half of a useful operating life).[178]

Pre-tax annualized costs provide insight on the total expenditure as incurred, while after-tax annualized costs are a more meaningful measure of impact on privately owned for-profit entities and incorporate approximate capital depreciation and other relevant tax treatments in the analysis. The EPA uses pre- and/or after-tax costs in different analyses, depending on the concept appropriate to each analysis (*i.e.,* social costs are calculated using pre-tax costs whereas cost-to-revenue screening-level analyses are conducted using after-tax costs).

The after-tax annualized costs of the final rule range between $479 million and $956 million for the lower and upper bound cost scenarios, respectively, whereas the pre-tax annualized costs range between $596 million and $1,164 million.

[177] See section 4.3.1 of *Human and Ecological Risk Assessment of Coal Combustion Residuals.*

[178] Assuming the same 40-year surface impoundment operating life used in the 2015 CCR rule record and acknowledging that these impoundments could be anywhere in that 40-year lifespan, the Agency uses the midpoint of 20-years as a reasonable approximation for purposes of ensuring that these costs are included in the main cost analyses of the final rule. To the extent that costs could be incurred before this date at some facilities and after this date at other facilities, these nationwide costs may either over- or underestimate the site-specific costs at any particular facility.

B. Social Costs

Social costs are the costs of the supplemental ELG from the viewpoint of society as a whole, rather than the viewpoint of regulated plants and owning entities (which are private costs). They include costs incurred by both private entities (*e.g.,* in complying with the regulation) and by the government (*e.g.,* in implementing the regulation). To calculate social costs, the EPA tabulated the pre-tax costs in the year they are estimated to be incurred, which varies across plants based on the estimated compliance year. The EPA performed the social cost analysis over a 25-year period of 2025 to 2049, which combines the length of the period during which plants are anticipated to install the control technologies (which could be as late as 2029) and the useful life of the longest-lived technology installed at any plant (20 years). The EPA calculated the social cost of the final rule using a two percent discount rate, following current OMB guidance in Circular A–4.[179]

As described further in section 10 of the RIA, there are no incremental increases in the cost to state governments to revise NPDES permits. Consequently, the only category of costs used to calculate social costs are those pre-tax costs estimated for steam electric power plants. Note that the annualized social costs differ from pre-tax industry compliance costs discussed in section VIII.A of this preamble due to differences in both the discount rate used (2 percent) and the year-explicit accounting of the costs. Whereas the costs in section VIII.A of this preamble represent the annualized costs of each option if they were incurred in 2024, the annualized social costs are estimated based on the stream of future costs starting in the year that individual plants are projected to comply with the requirements of the final rule. The final rule has estimated annualized incremental social costs of $536 million to $1,064 million.

C. Economic Impacts

The EPA assessed the economic impacts of this final rule in two ways: (1) a screening-level assessment of the cost impacts on existing EGUs at steam electric power plants and the entities that own those plants, based on a comparison of costs to revenue and (2) an assessment of the impacts within the context of the broader electricity market, which includes an assessment of changes in predicted plant closures attributable to the final rule. The following sections summarize the results of these analyses. The RIA discusses the methods and results in greater detail.

The first set of cost and economic impact analyses—at both the plant and parent company level—provides screening-level indicators of the impacts of costs for FGD wastewater, BA transport water, and CRL controls relative to historical operating characteristics of steam electric power plants incurring those costs (*i.e.,* level of electricity generation and revenue).[180] The EPA conducted these analyses for baseline and for the three regulatory options presented in table VII–1 of this preamble, then compared these impacts to understand the incremental effects of the regulatory options, including the final rule (Option B).

The second set of analyses looks at broader electricity market impacts, considering the interconnection of regional and national electricity markets. This analysis also looks at the distribution of impacts at the plant and EGU level. This second set of analyses provides insight on the impacts of the final rule on steam electric power plants, as well as the entire electricity market, including changes in capacity, generation, and wholesale electricity prices. The market analysis compares model predictions for the final rule to a base case that includes the predicted and observed economic and market effects of the 2020 rule and other environmental regulations.

1. Screening-Level Assessment

The EPA conducted a screening-level analysis of each regulatory option's potential impact on existing EGUs at steam electric power plants and parent entities based on cost-to-revenue ratios. For each of the two levels of analysis (plant and parent entity), the Agency assumed, for analytic convenience and as a worst-case scenario, that none of the compliance costs would be passed on to consumers through electricity rate increases and would instead be absorbed by the steam electric power plants and their parent entities. This assumption overstates the impacts of compliance expenditures since steam electric power plants that operate in a regulated market may be able to pass on changes in production costs to

[179] OMB (2023). Circular A–4: Regulatory Analysis. Washington DC. Available at *https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf.*

[180] As discussed in section VIII.A of this preamble, in analyzing the costs and benefits of the final rule, the EPA estimated that the costs to meet future legacy wastewater limitations would occur outside the period of analysis and therefore focused on the FGD wastewater, BA transport water and CRL wastestreams for this analysis.

consumers through changes in electricity prices. It is, however, an appropriate assumption for a screening-level estimate of the potential cost impacts.

a. Plant-Level Cost-to-Revenue Analysis

The EPA developed revenue estimates for this analysis using EIA data. The EPA then calculated the change in the annualized after-tax costs of the three regulatory options presented in table VII–1 of this preamble as a percentage of baseline annual revenues. See section 4 of the RIA for a more detailed discussion of the methodology used for the plant-level cost-to-revenue analysis.

Cost-to-revenue ratios are screening-level indicators of potential economic impacts. For this analysis, the EPA assessed plants incurring costs below one percent of revenue as unlikely to face economic impacts, plants with costs between one percent and three percent of revenue as having a higher chance of facing economic impacts, and plants incurring costs above three percent of revenue as having a still higher probability of economic impact.

Under the final rule (Option B), the EPA estimates that 50 to 72 plants would incur incremental costs greater than or equal to one percent of revenue under the lower and upper bound cost scenarios respectively, including 18 to 31 plants that have costs greater than or equal to three percent of revenue. An additional 91 to 98 plants would incur costs that are less than one percent of revenue. section 4.2 in the RIA provides results for the other regulatory options the EPA analyzed.

b. Parent Entity-Level Cost-to-Revenue Analysis

The EPA also assessed the economic impact of the regulatory options presented in table VII–1 of this preamble at the level of the firm that own steam electric power plants to analyze the potential impacts on these firms, referred to as ''parent entities.'' In this analysis, the domestic parent entity associated with a given plant is defined as the entity with the largest ownership share in the plant. For each parent entity, the EPA compared the incremental change in the total annualized after-tax costs and the total revenue for the entity to the baseline (see section 4 of the RIA for details). Following the methodology employed in the analyses for the 2015 and 2020 rules, the EPA considered a range of estimates for the number of entities owning an existing EGU at a steam electric power plant to account for partial information available for steam electric power plants that are not expected to incur ELG compliance costs.

Like the plant-level analysis above, cost-to-revenue ratios provide screening-level indicators of potential economic impacts, this time to the owning entities; higher ratios suggest a higher probability of economic impacts. The EPA estimates that the number of entities owning existing EGUs at steam electric plants ranges from 220 (lower-bound estimate) to 391 (upper-bound estimate), depending on the assumed ownership structure of plants not incurring ELG costs and not explicitly analyzed. The EPA estimates that under the final rule (Option B) and for the lower and upper bound cost scenarios, 13 to 17 parent entities would incur annualized costs representing one percent or more of their revenues, including 6 to 9 parent entity that would incur costs representing more than three percent of its revenue.

2. Electricity Market Impacts

To analyze the impacts of regulatory actions on the electric power sector, the EPA commonly uses IPM, a comprehensive electricity market optimization model that can evaluate such impacts within the context of regional and national electricity markets. The model is designed to evaluate the effects of changes in EGU-level electric generation costs on the total cost of electricity supply, subject to specified demand and emissions constraints. Use of a comprehensive market analysis system is important in assessing the potential impact of any power plant regulation because of the interdependence of EGUs that supply power to the electric transmission grid. Changes in electricity production costs at some EGUs can have a range of broader market impacts affecting other EGUs, including the average likelihood that various units are dispatched. The analysis also provides important insight on steam electric capacity closures (*e.g.,* retirements of EGUs that become uneconomical relative to other EGUs), based on a more detailed analysis of market factors than in the screening-level analyses above.

In contrast to the screening-level analyses, which are static and do not account for the interdependence of EGUs supplying power to the electric transmission grid, IPM accounts for potential changes in the generation profile of steam electric and other EGUs, as well as the consequent changes in market-level generation costs as the electric power market responds to changes in generation costs for steam electric EGUs due to the regulatory options. Additionally, in contrast to the screening-level analyses, in which the EPA assumed no cost pass-through of ELG compliance costs, IPM depicts production activity in wholesale electricity markets where the specific increases in electricity prices for individual markets would result in some recovery of compliance costs for plants. IPM is based on an inventory of U.S. utility- and nonutility-owned EGUs and generators that provide power to the integrated electric transmission grid, including plants to which the ELGs apply.

The EPA analyzed the final rule (Option B) using IPM to further inform the Agency's understanding of the potential impacts of the ELGs. The base case used for this analysis, which the EPA was developed using IPM Version 6, embeds an energy demand forecast that is derived from DOE's ''Annual Energy Outlook 2023.'' [181] The base case also includes the effects of the IRA provisions reflecting supply-side impacts, final Federal rules (*e.g.,* 2020 ELG rule, CSAPR and CSAPR Update, 2012 MATS rule, the 2014 CWA section 316(b) rule, and 2015 CCR rule and CCR Part A rule), and state rules and programs such as the Regional Greenhouse Gas Initiative, California's Global Warming Solutions Act, and state-level Renewable Portfolio Standards policies.

In analyzing the final rule, the EPA estimated incremental fixed and variable costs for the steam electric power plants and EGUs to comply with Option B. Because IPM is not designed to endogenously model the selection of wastewater treatment technologies as a function of electricity generation, effluent flows, and pollutant discharge, the EPA estimated these costs exogenously for each steam EGU and input these costs into the IPM model as fixed and variable O&M cost adders in addition to the costs already reflected in the base case, which included compliance with the 2020 ELG rule (the baseline analysis) and other applicable regulations. The EPA then ran IPM with these new cost estimates to determine the dispatch of EGUs that would meet projected demand at the lowest costs, subject to the same constraints as those in the baseline analysis. The estimated changes in plant- and EGU-specific production levels and costs—and, in turn, changes in the electric power sector's total costs and production profile—are key data elements in evaluating the expected national and regional effects of the final rule,

[181] U.S. Energy Information Administration (2023b). Annual Energy Outlook 2023. Available at *https://www.eia.gov/outlooks/aeo/.*

including closures or avoided closures of EGUs and plants.

The EPA considered impact metrics of interest at three levels of aggregation: (1) impact on national and regional electricity markets (all electric power generation, including steam and nonsteam electric power plants); (2) impact on steam electric power plants as a group, and (3) impact on individual steam electric power plants incurring costs. section 5 of the RIA discusses the first analysis; the sections below summarize the last two, which are further described in section 5 of the RIA. All results presented below are representative of modeled market conditions in the model year 2035, when the plants will have implemented changes to meet the revised ELGs.

a. Impacts on Existing Steam Electric Power Plants

The EPA used IPM results for 2035 to assess the potential impact of the final rule on existing EGUs at steam electric power plants. The purpose of this analysis is to assess any fleetwide changes from baseline impacts on EGUs at steam electric plants. Table VIII–2 of this preamble reports estimated results for existing EGUs at steam electric power plants, as a group. EPA looked at the following metrics: (1) incremental early retirements and capacity closures, calculated as the difference between capacity under the regulatory option and capacity under the baseline; (2) incremental capacity closures as a percentage of baseline capacity; (3) changes in electricity generation from plants subject to the ELGs; (4) changes in variable production costs per MWh, calculated as the sum of total fuel and variable O&M costs divided by net generation; and (5) changes in annual costs (fuel, variable O&M, fixed O&M, and capital). Items (1) and (2) provide important insight for determining the economic achievability of the ELG rule. Note that changes in electricity generation at steam electric power plants presented in table VIII–2 are attributable both to changes in retirements and changes in capacity utilization at operating EGUs and plants.

Table VIII-2. Estimated Impact of the Final Rule (Option B) on Steam Electric Power Plants as a Group in the Year 2035

Metric	Baseline Value	Change Attributable to the Final Rule as Compared to the Baseline	
		Value	Percent
Total capacity (MW)	220,237	-5,782	-2.6%
Early retirement or closure (MW)	104,544	5,782	5.5%
Early retirement or closure (number of plants)	78	5	6.4%
Total generation (GWh)	789,529	-23,579	-3.0%
Average variable production cost (2023$/MWh)	$20.18	-$0.21	-1.1%
Annual cost (million 2023$)	$28,580	-$840	-2.9%

MW = megawatt; MWh = megawatt-hour; GWh = gigawatt-hour = 1,000 MWh

Under the final rule, generation at steam electric power plants is projected to decrease by 23,579 GWh (3.0 percent) nationally when compared to baseline. IPM projects a net decline in total steam electric capacity by 5,782 MW (approximately 2.6 percent of total baseline steam electric capacity) due to early retirement attributable to this final rule. Five additional plants are projected to retire early under the final rule when compared to baseline. These incremental early retirements represent a 6.4 percent increase relative to projected baseline plant retirements, but only represent 0.7 percent of the total 688 steam electric power plants modeled in IPM. See section 5.2.2.2 in the RIA for details.

These findings suggest that the final rule can be expected to have small economic consequences for steam electric power plants as a group. Option B would affect the operating status of very few steam electric power plants, with five projected additional plant closures (including one plant that was not estimated to incur costs under Option B).

b. Impacts on Individual Plants Incurring Costs

To assess potential plant-level effects, the EPA also analyzed plant-specific changes attributable to the final rule for the following metrics: (1) capacity utilization (defined as annual generation (in MWh) divided by the product of capacity (MW) and 8,760 hours), (2) electricity generation, and (3) variable production costs per MWh, defined as variable O&M cost plus fuel cost divided by net generation. The analysis of changes in individual plants is detailed in section 5 of the RIA. The results indicate that most plants would experience only slight effects—*i.e.,* no change or a reduction/increase of less than one percent. Across the full set of steam electric power plants modeled, 36 plants would incur a reduction in generation of at least one percent; 17 of these plants are also estimated to incur a reduction in capacity utilization of at least one percent. At the same time, 21 plants would increase generation by at least one percent, and 10 plants see their capacity utilization increase by at least one percent. Of the subset of 35

steam electric power plants that were estimated to incur costs under the final rule (Option B), four plants would incur a decrease in generation, whereas four plants would see either no change or an increase in generation. Moreover, 13 plants for which the EPA estimated costs are projected to close in the baseline scenario, and four additional plants are projected to close under the final rule (Option B).

IX. Pollutant Loadings

In developing ELGs, the EPA typically evaluates the pollutant loading reductions of the final rule to assess the impacts of the compliance requirements on discharges from the whole industry. The EPA took the same approach to the one described above for plant-specific costs for estimating pollutant reductions associated with this rule. That is, the EPA compared the values to a baseline that reflects implementation of existing environmental regulations, including the 2020 rule for FGD wastewater and BA transport water.

The general methodology that the EPA used to calculate pollutant loadings is the same as that described in the 2020 rule. The EPA first estimated—on an annual, per plant basis—the pollutant discharge load associated with the technology bases evaluated for plants to comply with the 2020 rule requirements for FGD wastewater and BA transport water, accounting for the current or planned conditions at each plant. For CRL and legacy wastewater, the EPA estimated the pollutant discharge load associated with current discharges. For all wastestreams, the EPA similarly estimated plant-specific post-compliance pollutant loadings as the load associated with the technology bases for plants to comply with the effluent limitations in this rule. The EPA then calculated the changes in pollutant loadings at a particular plant as the sum of the differences between the estimated baseline and post-compliance discharge loadings for each applicable wastestream.

For plants that discharge indirectly to POTWs, the EPA adjusted the baseline and option loadings to account for pollutant removals expected from POTWs. These adjusted pollutant loadings for indirect dischargers therefore reflect the resulting discharges to receiving waters. For details on the methodology the EPA used to calculate pollutant loading reductions, see section 6 of the TDD.

A. FGD Wastewater

For FGD wastewater, the EPA continued to use the average pollutant effluent concentration with plant-specific discharge flow rates to estimate the mass pollutant discharge per plant for the baseline and the final rule. EPA used data compiled for the 2015 and 2020 rules as the initial basis for estimating discharge flow rates and updated the data to reflect retirements or other relevant changes in operation. As in the 2020 rule, the EPA also accounted for increased rates of recycle through the scrubber that would affect the discharge flow.

The EPA assigned pollutant concentrations for each analyte based on the operation of a treatment system designed to comply with baseline or the final rule. The EPA used data compiled for the 2020 rule to characterize FGD chemical precipitation plus LRTR effluent and chemical precipitation plus membrane filtration effluent. In addition, the EPA used data provided by industry and other stakeholders during the 2020 rule and 2023 proposed rule, as described in section IV of this preamble, to quantify bromide in FGD wastewater under baseline conditions and the final rule.

B. BA Transport Water

The EPA estimated baseline and post-compliance loadings for the final rule using pollutant concentrations for BA transport water and plant-specific flow rates. The EPA used data compiled for the 2020 rule as the basis for estimating BA transport water discharge flows and updated the data set to reflect retirements and other relevant changes in operation (*e.g.,* ash handling conversions, fuel conversions) that have occurred since collecting the 2020 rule data. Under the baseline, which reflects the 2020 rule requirement for the high recycle rate technology option (or BMP plan in the case of Merrimack Station), the EPA estimated discharge flows associated with the purge from remote MDS operation, based on the generating unit capacity and the volume of the remote MDS. Under the zero-discharge option, the EPA estimated a flow rate of zero.

C. CRL

For CRL, the EPA used the average pollutant effluent concentration with plant-specific discharge flow rates to estimate the mass pollutant discharge per plant for baseline and the final rule. The EPA used data compiled for the 2015 rule as the initial basis for estimating discharge flow rates and updated the data to reflect retirements. The EPA also used utilities' ''CCR Rule Compliance Data and Information'' websites to identify new landfills constructed since 2015 and waste management units that may discharge unmanaged CRL. For new landfills, the EPA used the 2015 methodology to estimate leachate flow proportionate to landfill size, if available, or as the median leachate volume (in gallons per day) calculated from the 2010 steam electric survey. For plants with EGUs no longer burning coal by 2034 (*e.g.,* retired, converted EGUs to natural gas), the EPA adjusted CRL discharge flow rates to account for an expected decrease in CRL volume following the closure of the waste management unit. For discharges of unmanaged CRL, the EPA estimated the volume of leachate-laden groundwater captured from pumping systems that draw down the groundwater elevation along the hydraulically downgradient cross-sectional width of the CCR management unit.

The EPA assigned pollutant concentrations for each analyte based on current operating conditions or treatment in place for the baseline and the operation of a treatment system designed to comply with the final rule. The EPA used data compiled for the 2015 rule, in addition to data gathered as part of this rulemaking (see section VI.A.3 of this preamble), to characterize untreated CRL. Consistent with its methodology for the 2015 rule, the EPA evaluated the new CRL data for use in the untreated CRL analytical dataset and incorporated the data acceptable for the loadings analyses (see section 6.4 of the TDD for more information). The EPA transferred the average FGD effluent concentrations for chemical precipitation, as it did in the 2015 rule.

D. Legacy Wastewater

The EPA estimated baseline and post-compliance loadings for the final rule using pollutant concentrations for legacy wastewater and plant-specific flow rates. The EPA used utilities' ''CCR Rule Compliance Data and Information'' websites to estimate the volume and type of CCR and water stored in impoundments. The EPA estimated the volume of impounded water (*i.e.,* decant wastewater) and dewatering wastewater for each impoundment primarily using information from the annual inspection reports. To estimate the flow rate, the EPA divided the total volume of legacy wastewater by the closure duration, specified in utilities' closure plans or estimated based on permit cycles. For surface impoundments where the total wastewater volume was unknown, the EPA used the median total estimated volume of wastewater from the impoundments in its analysis and a closure duration of seven years.

The EPA used 2015 rule surface impoundment effluent concentration

data sets to estimate baseline loadings as each impoundment in the population varies in the CCR material it contains, including FA, BA, combined ash, and FGD wastewater. The EPA transferred the average FGD effluent concentrations for chemical precipitation, as it did with CRL.

E. Summary of Incremental Changes of Pollutant Loadings from the Final Rule

Compared to the 2020 rule (baseline), the final rule results in a reduction of 656 million pounds of pollutants to surface waters annually. The EPA estimates pollutant removals associated with discharges of unmanaged CRL could amount to between 3.62 and 16.4 million pounds annually. See section VII.C.5 of this preamble for more information regarding the subcategory for discharges of unmanaged CRL.

X. Non-Water Quality Environmental Impacts

The elimination or reduction of one form of pollution may create or aggravate other environmental problems. Therefore, sections 304(b) and 306 of the CWA require the EPA to consider non-water quality environmental impacts (including energy requirements) associated with ELGs. Accordingly, the EPA has considered the potential impacts of this rule on air emissions, solid waste generation, and energy consumption. In general, to conduct this analysis, the EPA used the same methodology (with updated data as applicable) as it did for the analyses supporting the 2015 and 2020 rules. The following sections summarize the methodology and results. See section 7 of the supplemental TDD for additional details.

A. Energy Requirements

Steam electric power plants use energy when transporting ash and other solids on or off site, operating wastewater treatment systems (*e.g.,* chemical precipitation, membrane filtration, SDEs), or operating ash handling systems. For this final rule, the EPA considered whether there would be an associated change in the incremental energy requirements compared to the baseline. The EPA estimated the increase in energy usage in MWh for equipment added to the plant systems or in gallons of fuel consumed for transportation/operating equipment and summed the facility-specific estimates to calculate the net change in energy requirements from the baseline for the final rule.

The EPA estimated the amount of energy needed to operate wastewater treatment systems and ash handling systems based on the horsepower ratings of the pumps and other equipment. The EPA also estimated any changes in the fuel consumption associated with transporting solid waste and combustion residuals (*e.g.,* ash) from steam electric power plants to landfills (on- or off-site). The frequency and distance of transport depends on a plant's operation and configuration; specific factors include the volume of waste generated and the availability of either an on-site or off-site nonhazardous landfill and its distance from the plant. Table X–1 of this preamble shows the net change in annual electrical energy usage associated with the final rule compared to the baseline, as well as the net change in annual fuel consumption requirements associated with the final rule compared to the baseline.

Table X-1. Estimated Incremental Change in Energy Requirements Associated with the Final Rule Compared to the Baseline

Non-Water Quality Environmental Impact	Energy Use Associated with Final Rule
Electrical energy usage (MWh)	309,000
Fuel (thousand gallons)	116

The EPA estimates that energy use associated with discharges of unmanaged CRL could amount to as much as 280,000 MWh and 442 thousand gallons of fuel annually. See section VII.C.5 of this preamble for more information regarding the subcategory for discharges of unmanaged CRL.

B. Air Pollution

The final rule is expected to affect air pollution through three main mechanisms: (1) changes in auxiliary electricity use by steam electric power plants due to the need to operate wastewater treatment, ash handling, and other systems for compliance with regulatory requirements; (2) changes in transportation-related emissions due to the trucking of CCR waste to landfills; and (3) the change in the profile of electricity generation due to regulatory requirements. This section discusses air emission changes associated with the first two mechanisms and presents the corresponding estimated net changes in air emissions. See section XII.B.3 of this preamble for additional discussion of the third mechanism.

Steam electric power plants generate air emissions from operating transport vehicles, such as dump trucks, which release criteria air pollutants and GHGs. A decrease in energy use or vehicle operation would result in decreased air pollution.

The final rule is projected to result in changes in electrical energy compared to the baseline. To estimate the net air emissions associated with these changes, the EPA combined the energy usage estimates with air emission factors associated with electricity production to calculate air emissions associated with the incremental energy requirements. The EPA estimated NO_X, sulfur dioxide (SO_2), and CO_2 emissions using plant- or NERC-specific emission factors (tons/MWh) obtained from IPM for run year 2035.

To estimate net air emissions changes in the operation of transport vehicles, the EPA used the MOVES4.0 model to identify air emission factors (tons/mile) for the air pollutants of interest. The EPA estimated the annual number of miles that dump trucks moving ash or wastewater treatment solids to on- or off-site landfills would travel for the final rule. The EPA used these estimates to calculate the net change in air emissions for the final rule. Table X–2 of this preamble presents the estimated net change in air emissions associated with auxiliary electricity and transportation for the final rule.

Table X-2. Estimated Net Change in Industry-Level Air Emissions Associated with Auxiliary Electricity and Transportation for the Final Rule Compared to the Baseline

CO_2 (million tons/year)	CH_4 (thousand tons/year)	NO_X (thousand tons/year)	SO_2 (thousand tons/year)
0.14	0.008	0.09	0.12

CH_4 = methane

The EPA estimates that air emissions associated with discharges of unmanaged CRL could amount to as much as 0.048 million tons of CO_2, 0.022 thousand tons of NO_X, and 0.014 thousand tons of SO_2 annually. See section VII.C.5 of this preamble for more information regarding the subcategory for discharges of unmanaged CRL.

The modeled output from IPM predicts that compliance costs attributable to the final rule will result in changes in electricity generation compared to the baseline. These changes in electricity generation are, in turn, predicted to affect the amount of NO_X, SO_2, and CO_2 emissions from steam electric power plants.[182] Table X–3 of this preamble shows a summary of the net change in annual air emissions associated with the final rule for all three mechanisms for the IPM run year 2035. As with costs, the IPM run from the final rule reflects the range of non-water quality environmental impacts associated with the final rule. To provide some perspective on the estimated changes, the EPA compared the estimated change in air emissions to the net amount of air emissions generated in a year by all electric power plants throughout the United States. For a detailed breakout of each of the three sources of air emission changes, see section 7 of the TDD.

Table X-3. Estimated Net Change in Industry-Level Air Emissions Associated with Changes in Auxiliary Electricity, Transportation, and Electricity Generation for the Final Rule Compared to the Baseline in IPM Run Year 2035 and 2020 Emissions

Non-Water Quality Environmental Impact	Change in Emissions	2020 Emissions by Electric Power Generating Industry
CO_2 (million tons/year)	-13	1,650
NO_X (thousand tons/year)	-8.7	1,020
SO_2 (thousand tons/year)	-13	954

C. Solid Waste Generation and Beneficial Use

Steam electric power plants generate solid waste associated with sludge from wastewater treatment systems (*e.g.,* chemical precipitation). The EPA estimates the change in the amount of solids generated under the final rule compared to the baseline as 1.74 million tons per year. The EPA estimates that solid waste generation associated with the treatment of discharges of unmanaged CRL could amount to as much as 4.2 million tons per year.

The EPA also evaluated the potential impacts of diverting FA from current beneficial uses toward encapsulation of membrane filtration brine for disposal in a landfill. According to the latest American Coal Ash Association survey,[183] more than half of the FA generated by coal-fired power plants is being sold for beneficial uses rather than disposed of, and the majority of this beneficially used FA is replacing Portland cement in concrete. This also holds true for the specific facilities currently discharging FGD wastewater and expected to achieve zero discharge under the final rule, as seen by sales of FA in Schedule 8A of the 2021 EIA–923.[184] Summary statistics of the FA beneficial use percentage for these facilities is displayed in table X–4.

[182] The EPA also considered changes in particulate matter (see section XII.B.3 of this preamble). As explained in the BCA section 8.1: ''IPM outputs include estimated CO_2, NO_X, and SO_2 emissions to air from EGUs. The EPA also used IPM outputs to estimate EGU emissions of primary $PM_{2.5}$ based on emission factors described in U.S. EPA (2020c). Specifically, the EPA estimated primary $PM_{2.5}$ emissions by multiplying the generation predicted for each IPM plant type (ultrasupercritical coal without carbon capture and storage, combined cycle, combustion turbine, etc.) by a type-specific empirical emission factor derived from the 2016 National Emissions Inventory and other data sources. The emission factors reflect the fuel type (including coal rank), FGD controls, and state emission limits for each plant type, where applicable.''

[183] Available online at: *https://acaa-usa.org/wp-content/uploads/2022/12/2021-Production-and-Use-Survey-Results-FINAL.pdf.*

[184] Available online at: *https://www.eia.gov/electricity/data/eia923/.*

Table X-4. Percent of FA Sold for Beneficial Use at Facilities Discharging FGD Wastewater

Statistic	FA Percent Sold for Beneficial Use
Min	0%
10th	0%
25th	5%
Median	56%
Mean	48%
75th	83%
90th	93%
Max	100%

The EPA also evaluated FA sales at facilities with CRL discharges that achieve zero discharge under the final rule in Schedule 8A of the 2021 EIA–923.[185] Summary statistics of the FA beneficial use percentage for these facilities are displayed in table X–5.

Table X-5. Percent of FA Sold for Beneficial Use at Facilities Discharging CRL

Statistic	FA Percent Sold for Beneficial Use
Min	0%
10th	0%
25th	0%
Median	23%
Mean	38%
75th	81%
90th	100%
Max	100%

In the CCR rule,[186] the EPA noted that FA replacing Portland cement in concrete would result in significant avoided environmental impacts to energy use, water use, GHG emissions, air emissions, and waterborne wastes.

For the final rule, the EPA is identifying zero-discharge systems as the technology basis for establishing BAT limitations to control pollutants discharged in FGD wastewater and CRL. More specifically, the technology basis for BAT is membrane filtration systems, SDEs, and thermal evaporation systems (see section VII.B of this preamble for more details). For the final rule, the EPA made several updates to its FA analysis, including the following: revising estimates of the amount of FA required for brine encapsulation, revising estimates of the amount of FA available at each plant for brine encapsulation, adding costs for steam electric power plants that would need to purchase additional FA for brine encapsulation, adding costs for disposal of the additional FA, and revising compliance costs by selecting the least costly zero-discharge technology for FGD and/or CRL. See section 5 of the TDD and the EPA's *2024 Steam Electric Supplemental Final Rule: Fly Ash Analysis* memorandum (DCN SE11692) for more details. The EPA found that 17 of the 26 steam electric power plants with FGD wastewater discharges produce enough FA for the EPA's estimated brine encapsulation if they do not sell any FA. Two plants with a FA deficit are expected to retire or undergo fuel conversion prior to December 31, 2034, and will not need to meet zero-discharge requirements under the final rule. The EPA expects that the other seven plants with a FA deficit will install SDEs (or another technology at a lower cost) that will not require the use of FA for encapsulation to meet the final rule requirements. In addition, plants may be able to manage the FA deficit through FGD scrubber purge management and using a different brine encapsulation recipe (*e.g.,* include additional lime).

The EPA also found 61 of the 90 steam electric power plants with CRL discharges produce enough FA for the EPA's estimated brine encapsulation, even after accounting for encapsulation for FGD wastewater treatment. Thirteen of the 29 plants with a FA deficit will retire or undergo fuel conversion prior to December 31, 2034, and will not need to meet zero discharge requirements under the final rule. The EPA expects that the other 16 plants with a FA deficit will either purchase FA (accounted for in the EPA's cost estimates), manage the deficit using approaches described above for FGD wastewater, or install SDEs (or another technology at a lower cost) which will

[185] Available online at: *https://www.eia.gov/electricity/data/eia923/.*

[186] Available online at: *https://www.regulations.gov.* Docket ID: EPA–HQ–RCRA–2009–0640.

not require the use of FA for encapsulation to meet the final rule requirements. See additional discussion in section VII.B.1.a of this preamble.

D. Changes in Water Use

Steam electric power plants typically use water for handling solid waste, including ash, and for operating wet FGD scrubbers. The technology basis for FGD wastewater in the 2020 rule, chemical precipitation plus LRTR, was not expected to reduce or increase the volume of water used. Under this final rule, plants that install a membrane filtration or thermal evaporation system for FGD wastewater treatment are assumed to decrease their water use compared to the baseline by recycling all permeate back into the FGD system, which would avoid the costs of pumping or treating new makeup water. Therefore, the EPA estimated the reduction in water use resulting from membrane filtration or thermal evaporation treatment as equal to the estimated volume of the permeate stream from the membrane filtration system.

The BA transport technologies associated with the baseline and the final rule for BA transport water eliminate or reduce the volume of water used by wet sluicing BA operating systems. The 2020 rule established limitations based on plants operating a high recycle rate system, allowing up to a 10 percent purge of the total system volume. As part of this rule, the EPA is establishing zero-discharge requirements for BA handling. Thus, for the final rule, the EPA expects to see a decrease in water use for BA handling operations because plants that operate zero discharge BA handling systems are assumed to decrease their water use compared to baseline by recycling all transport water back to the BA handling system, which would avoid the costs of pumping or treating new makeup water. The EPA estimated the reduction in water use resulting from complete recycle as equal to the estimated volume of the percent purge (estimated to be 2 percent).

The EPA does not expect a change in water use associated with the treatment technology considered for the treatment of CRL or legacy wastewater as part of this final rule.

Overall, the EPA estimates that plants would decrease their water use by 5.52 million gallons per day (MGD) compared to the baseline under the final rule.

XI. Environmental Assessment

A. Introduction

The EPA conducted an environmental assessment for this final rule. The Agency reviewed available literature on the documented environmental and human health effects of the pollutants discharged in steam electric power plant FGD wastewater, BA transport water, CRL, and legacy wastewater. The EPA conducted modeling to determine the impacts of pollutant discharges from the plants that are regulated by this final rule. For the reasons described in section VIII of this preamble, the baseline for these analyses appropriately consists of the environmental and human health results of achieving the 2020 rule requirements (the same baseline the EPA used to evaluate costs, benefits, and pollutant loadings). Under this assessment, the EPA compared the change in impacts associated with the final rule to those projected under the baseline.

The EA presents information from the EPA's review of the scientific literature and documented cases of impacts of pollutants discharged in steam electric power plant wastewater on human health and the environment, as well as a description of EPA's modeling methodology and results. The EA contains information on literature that the EPA has reviewed since the 2020 rule, updates to the environmental assessment analyses, and modeling results for the final rule. The 2015 EA (EPA–821–R–15–006) and 2020 EA (EPA 821–R–20–002) provide information from the EPA's earlier review of the scientific literature and of documented cases of the impacts on human health and the environment associated with the wider range of steam electric power plant wastewater discharges addressed in the 2015 rule, as well as a full description of the EPA's modeling methodology.

Current scientific literature indicates that untreated steam electric power plant wastewaters, such as FGD wastewater, BA transport water, CRL, and legacy wastewater, contain large amounts of a wide range of pollutants, some of which are toxic and bioaccumulative and cause detrimental environmental and human health impacts. For additional information, see section 2 of the EA. The EPA also considered environmental and human health effects associated with changes in air emissions, solid waste generation, and water withdrawals. sections X and XII of this preamble discuss these effects.

B. Updates to the Environmental Assessment Methodology

For this rule, the EPA used the steady-state, national-scale immediate receiving water (IRW) model to evaluate the direct and indirect discharges from steam electric power plants. This model was also used for the 2015 and 2020 ELG rules and 2015 CCR rule. The model focused on impacts within the immediate surface waters where discharges occurred (defined as the closest segments of approximately 0.25 miles to five miles long). The EPA also modeled receiving water concentrations downstream from steam electric power plant discharges using a downstream fate and transport model (*see* section XII). For this final rule, the Agency updated pollutant-specific benchmarks based on revised guidance and standards. The environmental assessment also incorporates changes to the industry profile outlined in section V of this preamble.

C. Outputs From the Environmental Assessment

Based on comparisons to the baseline, the EPA estimated environmental and ecological changes associated with the changes in pollutant loadings expected under the final rule. These environmental and ecological changes include changes in impacts to wildlife and humans. More specifically, the environmental assessment evaluated changes in: (1) surface water quality, (2) impacts to wildlife, (3) number of receiving waters with potential human health cancer risks, (4) number of receiving waters with potential to cause noncancer human health effects, and (5) metal and nutrient discharges to sensitive waters (*e.g.,* CWA section 303(d) impaired waters).[187] The EPA also evaluated other unqantified environmental changes (*e.g.,* ground water quality and attractive nuisances), as well as further impacts as described in section XII.

As described in the EA, the EPA focused its quantitative analyses on the changes in environmental and human health impacts associated with exposure to toxic, bioaccumulative pollutants via the surface water pathway. The EPA modeled changes levels of toxic, bioaccumulative pollutants in

[187] For the proposed rule, the EPA evaluated potential cumulative impacts (joint toxic action) based on interaction profiles (*Supplemental Environmental Assessment for the Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (EPA–821–R–23–004). DCN SE10328). EPA did not receive any comment on the analysis and provides a qualitative summary in the EA for the final rule based on the previous analysis.

discharges of FGD wastewater, BA transport water, CRL, and legacy wastewater into rivers, streams, and lakes, including reservoirs. The EPA also addressed environmental impacts from nutrients in the EA, as well as in a separate analysis in section XII of this preamble.

The environmental assessment concentrates on impacts to aquatic life based on changes in surface water quality; impacts to aquatic life based on changes in sediment quality in surface waters; impacts to wildlife from consumption of contaminated aquatic organisms; and impacts to human health from consumption of contaminated fish and water. The EA discusses, with quantified results, the estimated environmental improvements within the immediate receiving waters due to the pollutant loading reductions associated with the final rule compared to the 2020 rule.

XII. Benefits Analysis

This section summarizes the national environmental benefits due to changes in steam electric power plant discharges. The BCA report provides additional details on the benefits methodologies and analyses. The analysis methodology for quantified benefits is generally the same that EPA used for the 2015 and 2020 rule*s,* but with revised inputs and assumptions that reflect updated data and regulatory options. Consistent with the analysis of social costs, the EPA analyzed benefits of changes occurring in 2025 through 2049. The rule benefits are projected to begin accruing when each plant implements the control technologies needed to comply with any applicable BAT effluent limitations or pretreatment standards. As discussed in the BCA, for the purpose of the economic impact and benefit analysis, EPA generally estimates that plants will implement control technologies to meet the applicable rule limitations and standards as their permits are renewed, and no later than December 31, 2029. This schedule recognizes that control technology implementation is likely to be staggered over time across the universe of steam electric power plants. The period of analysis extends to 2049 to capture the estimated life of the compliance technology at any steam electric power plant (20 or more years), starting from the year of technology implementation, which can be as late as 2029. Benefits are annualized over 25 years.

A. Categories of Benefits Analyzed

Table XII–1 of this preamble summarizes benefit categories associated with the final rule. Analyzed benefits fall into four broad categories: (1) human health benefits from surface water quality improvements, (2) ecological conditions and recreational use effects from surface water quality changes, (3) market and productivity benefits, and (4) air-related effects.[188] Within these broad categories, the EPA was able to assess the benefits of the final rule with varying degrees of completeness and rigor. Where possible, the EPA quantified the expected changes in effects and estimated monetary values. However, data limitations, modeling limitations, and gaps in the understanding of how society values certain environmental changes prevented the EPA from quantifying and/or monetizing some benefit categories.

The following section summarizes the EPA's analysis of the benefit categories the Agency was able to partially quantify and/or monetize to various degrees (identified in the columns of table XII–1 of this preamble). The EPA reviewed comments received in response to the proposed rule on the extent to which partially quantified benefits (*e.g.,* some health endpoints) or unquantified benefits (*e.g.,* cost savings to drinking water systems) could be more fully quantified and/or monetized. In the final rule analysis, the Agency revised its approach to quantify and monetize additional benefits, including those associated with avoided cardiovascular disease premature mortality from reduced lead exposure and those associated with avoided drinking water treatment costs. The final rule also affects additional benefit categories that the Agency was not able to quantify or monetize at all. The BCA further describes some of these important nonmonetized benefits. The EPA notes that all human health and environmental improvements discussed in the EA also represent benefits of the final rule (whether quantified or unquantified).

[188] Consistent with Office of Management and Budget Circular A–4 (2023), EPA appropriately considers additional benefits of this action (*e.g.,* air benefits). Circular A–4 (2023) states:

> Your analysis should look beyond the obvious benefits and costs of your regulation and consider any important additional benefits or costs, when feasible. . . . These sorts of effects sometimes are referred to by other names: for example, indirect or ancillary benefits and costs, co-benefits, or countervailing risks.

Table XII-1. Summary of Estimated Benefits Categories

Benefit Category	Quantified and Monetized	Quantified, but Not Monetized	Neither Quantified nor Monetized (Analyzed Qualitatively)
Human Health Benefits from Surface Water Quality Improvements			
Changes in incidence of bladder cancer from exposure to total trihalomethanes (TTHM) in drinking water	✓		
Changes in incidence of cancer from arsenic exposure via consumption of self-caught fish		✓	
Changes in incidence of cardiovascular disease from lead exposure via consumption of self-caught fish	✓		
Changes in incidence of other cancer and noncancer adverse health effects (*e.g.*, reproductive, immunological, neurological, circulatory, or respiratory toxicity) due to exposure to arsenic, lead, cadmium, and other toxics from consumption of self-caught fish or drinking water		✓	
Changes in IQ loss in children from lead exposure via consumption of self-caught fish, including changes in specialized education needs for children from lead exposure via consumption of self-caught fish	✓		
Changes in IQ loss in infants from *in utero* mercury exposure via maternal consumption of self-caught fish	✓		
Changes in health hazards from exposure to pollutants in waters used recreationally (*e.g.*, swimming)		✓	
Ecological Condition and Recreational Use Effects from Surface Water Quality Changes			
Benefits from changes in surface water quality, including: aquatic and wildlife habitat; water-based recreation, including fishing, swimming, boating, and near-water activities; aesthetic benefits, such as enhancement of adjoining site amenities (*e.g.*, residing, working, traveling, and owning property near the water);[a] and nonuse value (existence, option, and bequest value from improved ecosystem health)[a]	✓		
Benefits from protection of threatened and endangered species		✓	
Changes in sediment contamination			✓
Market and Productivity Benefits			
Changes in water treatment costs for municipal drinking water	✓		
Changes in water treatment costs for irrigation water and industrial process			✓
Changes in commercial fisheries yields			✓
Changes in tourism and participation in water-based recreation			✓
Changes in property values from water quality changes			✓
Changes in maintenance dredging of navigational waterways and reservoirs due to changes in sediment discharges	✓		
Air-Related Effects			
Human health benefits from changes in morbidity and mortality from exposure to NO_X, SO_2, and $PM_{2.5}$	✓		
Avoided climate change impacts from GHG emissions	✓		

[a] Some, although not necessarily all, of these values are implicit in the total willingness to pay (WTP) for water quality improvements.

B. Quantification and Monetization of Benefits

1. Human Health Effects From Surface Water Quality Changes

Changes in pollutant discharges from steam electric power plants affect human health in multiple ways. Exposure to pollutants in steam electric power plant discharges via consumption of fish from affected waters can cause a wide variety of adverse health effects, including cancer, kidney damage, nervous system damage, fatigue, irritability, liver damage, circulatory system damage, vomiting, diarrhea, and IQ loss. Exposure to drinking water containing brominated disinfection byproducts can cause adverse health effects such as bladder cancer and reproductive and fetal development issues. Because the final rule will reduce discharges of steam electric pollutants into waterbodies that directly receive or are downstream from these discharges, it may reduce the incidence of associated illnesses, even if by relatively small amounts.

Due to data limitations and uncertainties, the EPA can only monetize a subset of the health benefits associated with changes in pollutant discharges from steam electric power plants resulting from the final rule. The EPA estimated changes in the number of individuals experiencing adverse human health effects in the populations exposed to steam electric discharges and/or altered exposure levels and valued these changes using different monetization methods for different benefit endpoints.

The EPA estimated changes in health risks from the consumption of contaminated fish from waterbodies within 50 miles of households. The EPA used Census block group population data and region-specific average fishing rates to estimate the exposed population. The EPA used cohort-specific fish consumption rates and waterbody-specific fish tissue concentration estimates to calculate potential exposure to steam electric pollutants in recreational fishers' households. Cohorts were defined by age, sex, race/ethnicity, and fishing mode (recreational or subsistence). EPA used these data to quantify and monetize changes in three categories of human health effects, which are further detailed in the BCA Report: (1) reduction in IQ loss from lead exposure via fish consumption in children aged zero to seven, (2) reduction in cardiovascular disease premature mortality from lead exposure via fish consumption and (3) reduction in *in utero* mercury exposure via maternal fish consumption and associated IQ loss. The EPA also analyzed the reduction in the incidence of skin cancer from arsenic exposure via fish consumption but found negligible changes and therefore did not monetize the associated benefits.

EPA estimated the annualized human health benefits of surface water quality changes of the final rule and the resultant reduction in pollutant exposure from consuming self-caught fish to range between $2.18 million and $2.45 million using a two percent discount rate. Most of these monetized benefits are associated with the changes in mercury exposure. section 5 of the BCA provides additional detail on the methodology.

The EPA also estimated changes in bladder cancer incidence from the use and consumption of drinking water with lower levels of total trihalomethanes (TTHMs) resulting from reductions in bromide discharges under the final rule. The EPA estimated changes in cancer risks within populations served by drinking water treatment plants with intakes on surface waters affected by bromide discharges from steam electric power plants. The EPA used the service area of each public water system to estimate and characterize the exposed population. The EPA modeled changes in waterbody-specific bromide concentrations and changes in facility-specific TTHM concentrations at drinking water treatment facilities to calculate potential reductions in TTHM exposure and associated health benefits. To value changes in the economic burden associated with cancer morbidity, the EPA used base WTP estimates from Bosworth, Cameron, and DeShazo (2009) for colon/bladder cancer. To value changes in excess mortality from bladder cancer, the EPA used the estimated value of a statistical life (VSL) for each year in the period of analysis (from $13.54 million per death in 2025 to $16.36 million per death in 2049).

The final rule is estimated to result in a total of 98 avoided cancer cases and 28 avoided premature excess deaths by reducing TTHM exposure during the period 2025–2049. The associated annualized benefits are $13.4 million using a two percent discount rate.

The formation of TTHM in a particular water treatment system is a function of several site-specific factors, including chlorine, bromine, and organic carbon concentrations; and temperature and pH of the water; and the system residence time. The EPA did not collect site-specific information on these factors at each potentially affected drinking water treatment facility. Instead, the EPA's analysis only addresses the estimated site-specific changes in bromides. The EPA used the national relationship between changes in TTHM exposure and changes in incidence of bladder cancer modeled by Regli et al. (2015) [189] and Weisman et al. (2022).[190] Thus, while the national changes in TTHM exposure and bladder cancer incidence are the EPA's best estimate given estimated changes in bromide, the EPA cautions that estimates for any specific drinking water treatment facility could be over- or underestimated. Additional details on this analysis are provided in section 4 of the BCA.

2. Ecological Condition and Recreational Use Effects from Changes in Surface Water Quality Improvements

The EPA evaluated whether the final rule would alter aquatic habitats and human welfare by reducing concentrations of harmful pollutants such as arsenic, cadmium, chromium, copper, lead, mercury, nickel, selenium, zinc, nitrogen, phosphorus, and suspended sediment relative to baseline. These changes may affect the usability of some recreational waters relative to baseline, thereby affecting recreational users. Changes in pollutant loadings can also change the attractiveness of recreational waters by making recreational trips more or less enjoyable. The final rule may also change nonuse values stemming from bequest, altruism, and existence motivations. Individuals may value water quality maintenance, ecosystem protection, and healthy species populations independent of any use of those attributes.

The EPA uses a water quality index (WQI) to translate water quality measurements, gathered for multiple parameters that indicate various aspects of water quality, into a single numerical indicator. The indicator reflects achievement of quality consistent with the suitability for certain uses. The WQI includes seven parameters: dissolved oxygen, biochemical oxygen demand, fecal coliform, total nitrogen, total phosphorus, TSS, and one aggregate

[189] Regli, S., Chen, J., Messner, M., Elovitz, M.S., Letkiewicz, F.J., Pegram, R.A., . . . Wright, J.M. (2015). *Estimating Potential Increased Bladder Cancer Risk Due to Increased Bromide Concentrations in Sources of Disinfected Drinking Waters.* Environmental Science & Technology, 49(22), 13094–13102. Available online at: *https://doi.org/10.1021/acs.est.5b03547.*

[190] Weisman, R., Heinrich, A., Letkiewicz, F., Messner, M., Studer, K., Wang, L., . . . Regli, S. (2022). *Estimating National Exposures and Potential Bladder Cancer Cases Associated with Chlorination DBPs in U.S. Drinking Water.* Environmental Health Perspectives, 130:8, 087002–1–087002–10. Available online at: *https://ehp.niehs.nih.gov/doi/full/10.1289/EHP9985.*

subindex for toxics. The EPA modeled changes in four of these parameters and held the remaining parameters (dissolved oxygen, biochemical oxygen demand, and fecal coliform) constant for the purposes of this analysis.

The EPA estimated the change in monetized benefit values using an updated version of the meta-regressions of surface water valuation studies used in the benefit analyses of the 2015 and 2020 rules. The meta-regressions quantify average household WTP for incremental improvements in surface water quality. section 6 of the BCA provides additional detail on the valuation methodology.

An estimated 58.9 million households reside in Census block groups that are within 100 miles of reaches that are affected by the final rule.[191] The central tendency estimate of the total WTP for water quality changes associated with reductions in metal pollutants (arsenic, cadmium, chromium, copper, lead, mercury, zinc, and nickel), nonmetal pollutants (selenium), nutrient pollutants (phosphorus and nitrogen under the final rule is $1.24 million using a two percent discount rate. The average WTP per household is $0.02 per year.

3. Changes in Air-Quality-Related Effects

The EPA expects the final rule to affect air pollution through three main mechanisms: (1) changes in auxiliary electricity use by steam electric facilities due to the need to operate wastewater treatment, ash handling, and other systems for compliance with the final rule; (2) changes in transportation-related air emissions due to changes in the trucking of CCR waste to landfills; and (3) changes in the electricity generation profile due to increases in wastewater treatment costs compared to baseline and the resulting changes in EGU relative operating costs.

Changes in the electricity generation profile can increase or decrease air pollutant emissions because emission factors vary for different types of EGUs. For this analysis, the changes in air emissions are based on the change in dispatch of EGUs as projected by IPM after overlaying the costs of complying with the final rule onto EGUs' production costs. As discussed in section VIII of this preamble, the IPM analysis accounts for the effects of other regulations on the electric power sector, as well as provisions of the IRA.

The EPA evaluated potential effects resulting from net changes in air emissions of five pollutants: CO_2, CH_4, NO_X, SO_2, and primary $PM_{2.5}$. CO_2 and CH_4 are key GHGs linked to a wide range of climate-related effects. CO_2 is also the main GHG emitted from coal power plants. NO_X and SO_2 are precursors to $PM_{2.5}$, which are also emitted directly, and NO_X is an ozone precursor. These air pollutants cause a variety of adverse health effects including premature mortality, nonfatal heart attacks, hospital admissions, emergency department visits, upper and lower respiratory symptoms, acute bronchitis, aggravated asthma, lost work and school days, and acute respiratory symptoms.

Table XII–2 of this preamble shows the changes in emissions of CO_2, CH_4, NO_X, SO_2, and primary $PM_{2.5}$ under the final rule relative to the baseline for selected IPM run years. The final rule will result in a net reduction in air emissions of four pollutants, and a small increase in CH_4 emissions due to the increased trucking of CCR waste to landfills. This effect is driven mostly by the estimated changes in the profile of electricity generation, as emission reductions due to shifts in modeled EGU dispatch and energy sources offset relatively small increases in air emissions from increased electricity use and trucking by steam electric power plants.

Table XII-2. Estimated Changes in Air Pollutant Emissions Under the Final Rule Compared to Baseline

Year	CO_2 (Million Short Tons/Year)	CH_4 (Thousand Short Tons/Year)	NO_X (Thousand Short Tons/Year)	SO_2 (Thousand Short Tons/Year)	Primary $PM_{2.5}$ (Thousand Short Tons/Year)
2028	-16.4	0.0042	-8.9	-10.7	-0.63
2030	-10.8	0.0083	-7.3	-2.4	-0.38
2035	-12.6	0.0083	-8.7	-12.5	-0.25
2040	-1.9	0.0083	-3.1	-2.2	-0.16
2045	-1.3	0.0083	-0.6	-0.9	-0.09
2050	-0.6	0.0079	-0.4	-0.7	-0.12

The EPA estimated the monetized value of human health benefits among populations exposed to changes in $PM_{2.5}$ and ozone. The final rule is expected to alter the emissions of primary $PM_{2.5}$, SO_2 and NO_X, which will in turn affect the level of $PM_{2.5}$ and ozone in the atmosphere. Using photochemical modeling, the EPA predicted the change in the annual average $PM_{2.5}$ and summer season ozone across the United States. The EPA next quantified the human health impacts and economic value of these changes in air quality using the environmental Benefits Mapping and Analysis Program—Community Edition.

To estimate the climate benefits associated with changes in CO_2 and CH_4 emissions, the EPA used social cost of greenhouse gas (SC–GHG) estimates specifically, estimates of the social cost of carbon (SC–CO_2) and social cost of methane (SC–CH_4). The SC–GHG is an estimate of the monetary value of the net harm to society associated with emitting a metric ton of the GHG in question into the atmosphere in a given

[191] A reach is a section of a stream or river along which similar hydrologic conditions exist, such as discharge, depth, area, and slope.

year, or the benefit of avoiding those emissions.[192]

To estimate the net climate benefits of CO_2 emission reductions expected from the final rule and disbenefits of increases in CH_4 emissions, the EPA used the SC–GHG estimates presented in the 2023 final rule Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (U.S. EPA, 2023). These estimates reflect recent advances in the scientific literature on climate change and its economic impacts and incorporate recommendations made by the National Academies (National Academies, 2017). See section 8 of the BCA for more discussion of the SC–GHG values.

Table XII–3 of this preamble shows the annualized climate change, $PM_{2.5}$, and ozone-related human health benefits for the final rule. Climate change benefits are presented for the three near-term Ramsey discount rates used in developing the SC–GHG values, whereas the $PM_{2.5}$ and ozone-related human health benefits are based on long-term ozone exposure mortality risk estimates and with a two percent discount rate. See section 8 of the BCA for benefits based on pooled short-term ozone exposure mortality risk estimates.

Table XII-3. Annualized Benefits of Estimated Changes in Air Pollutant Emissions Under the Final Rule Compared to the Baseline (Millions of 2023$)

SC-GHG Near-term Ramsey Discount Rate	Climate Change Benefits	PM2.5 and Ozone Related Human Health Benefits at 2% Discount Rate[a]	Total
2.5%	$990	$1,600	$2,600
2.0%	$1,600	$1,600	$3,200
1.5%	$2,600	$1,600	$4,200

[a] Reflects long-term ozone exposure mortality risk estimate.

The estimates of monetized benefits shown here do not include several important benefit categories, such as direct exposure to SO_2, NO_X, and HAPs, including mercury and hydrogen chloride. Although the EPA does not have sufficient information or modeling available to provide monetized estimates of changes in exposure to these pollutants for the final rule, the EPA includes a discussion of these unquantified benefits in the BCA. For more information on the benefits analysis, see section 8 of the BCA.

4. Other Quantified and/or Monetized Benefits

a. Changes in Drinking Water Treatment Costs

The final rule will decrease discharges of pollutants that affect the costs of treating drinking water. TSS affects turbidity of source water, which drinking water systems treat by adding chemical coagulants to bond to the sediment particles. Drinking water systems thus accrue incremental costs related to purchases of coagulants as well as costs from disposal of coagulant sediment sludge. In addition, drinking water systems address taste and odor issues linked to excess nutrients (such as nitrogen) and associated eutrophication in source water. The EPA identified drinking water systems whose source waters are likely to see reductions in TSS and total nitrogen under the final rule, then estimated changes in source water concentrations of the pollutants for those systems. The EPA then estimated treatment cost savings associated with reductions in TSS and total nitrogen using a treatment cost elasticity approach (see Price and Heberling (2018) for a review of the literature on drinking water treatment cost elasticities). The EPA estimated cost changes relating to treatment O&M costs alone, assuming no net savings from any capital improvements drinking water systems already made. The EPA did not quantify avoided drinking water treatment costs associated with reductions in pollutants such as phosphorus, halogens, and metals due to uncertainties in the elasticity between source water concentrations of these parameters and drinking water treatment costs, lack of information on baseline concentrations of these pollutants at source water intakes, and the possibility of double-counting treatment cost savings for particular pollutants. The EPA expects that the final rule will provide relatively small annualized benefits from reductions in nitrogen and total suspended solids in the form of drinking water treatment cost savings of $460,000 to $552,000 per year, calculated using a 2 percent discount rate.

b. Changes in Dredging Costs

The final rule affects discharge loadings of various categories of pollutants, including TSS. As a result, the final rule is expected to change the rate of sediment deposition in affected waterbodies, including navigable waterways and reservoirs that require dredging for maintenance. The EPA estimated very small benefits from changes in sedimentation and associated maintenance dredging costs in reaches and reservoirs affected by steam electric power plant discharges. section 9 of the BCA provides additional detail on the methodology.

c. Benefits to Threatened and Endangered Species

To assess the potential for the final rule to benefit threatened and endangered species (both aquatic and terrestrial) relative to the 2020 ELG baseline, the EPA analyzed the overlap between waters expected to see reductions in wildlife water quality criteria exceedance status under the final rule and the known critical habitat

[192] In principle, the SC–GHG includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–GHG therefore, reflects the societal value of reducing emissions of by one metric ton. The EPA and other Federal agencies began regularly incorporating estimates of SC–CO_2 in their benefit-cost analyses conducted under Executive Order 12866 since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing CO_2 emissions in a rulemaking process.

locations of high-vulnerability threatened and endangered species. The EPA examined the life history traits of potentially affected threatened and endangered species and categorized the species by potential for population impacts due to surface water quality changes. Section 7 of the BCA provides additional detail on the methodology. The EPA's analysis showed that, of the species categorized as having higher vulnerability to water pollution, 30 have known critical habitats overlap with surface waters affected by steam electric power plant discharges. Improvements under the final rule between 2025 and 2029 are estimated to potentially benefit 10 of these species, whereas improvements projected after 2030 are estimated to benefit 12 species. Principal sources of uncertainty include the specifics of how changes under the final rule will impact threatened and endangered species, exact spatial distribution of the species, and additional species of concern not considered.

C. Total Monetized Benefits

Using the analysis approach described above, the EPA estimated annualized benefits of the final rule for all monetized categories. The final rule has monetized benefits estimated at $3,217 million using a two percent discount rate, as shown in table XII–4.

Table XII-4. Summary of Total Estimated Annualized Monetized Benefits at Two Percent [Millions of 2023$]

Benefit Category	Annualized Benefits (Million 2023$, 2 Percent Discount)
Human Health Effects from Water Quality Changes	
Changes in IQ losses in children from exposure to lead[a]	<$0.01
Changes in cardiovascular disease premature mortality from exposure to lead	$0.16 – $0.43
Changes in IQ losses in children from exposure to mercury	$1.98
Reduced cancer risk from disinfection byproducts in drinking water	$13.37
Ecological Conditions and Recreational Use Changes	
Use and nonuse values for water quality improvements	$1.24
Market and Productivity[a]	
Changes in drinking water treatment costs	$0.46 – $0.55
Changes in dredging costs[a]	<$0.01
Air-Related Effects	
Changes in GHG air emissions[b,c]	$1,600
Changes in human health effects from Changes in NO_X and SO_2 emissions[b]	$1,600
Total	**$3,217**

[a] An annualized benefit of "<$0.01" indicates that the monetary value is greater than $0 but less than $0.01 million.

[b] Values for air-quality related effects are rounded to two significant figures.

[c] Changes in CO_2 and CH_4 emissions monetized using SC-GHG estimates under the 2% near-term Ramsey discount rate. See section XII.B.3 and section 8 in the BCA for benefits monetized using SC-GHG estimates based on 1.5% and 2.5% near-term Ramsey discount rates.

D. Additional Benefits

The monetary value of the final rule's effects on social welfare does not account for all effects of the rule because, as described above, the EPA is currently unable to quantify and/or monetize some categories. The EPA anticipates that the final rule will also generate important unquantified benefits, including but not limited to:

- health benefits to over 30 million people who, due to reductions in PWS-level arsenic, lead, and thallium concentrations, will experience reductions in unmonetized cancer and non-cancer effects from exposure to toxic pollutants from consumption of fish or drinking water;
- unquantified and unmonetized averted IQ losses and educational effects from childhood lead exposure and *in-utero* mercury exposure from fish consumption by households that do not engage in recreational or subsistence fishing;
- improved habitat conditions for plants, invertebrates, fish, amphibians, and the wildlife that prey on aquatic organisms;
- enhanced ecosystem productivity and health, including reduced toxic discharges into habitats of over 100 high-vulnerability threatened and endangered species;

- additional changes to water treatment costs for drinking water, irrigation, and agricultural uses;
- changes in fisheries yield and harvest quality from aquatic habitat changes;
- changes in health hazards from recreational exposures; and
- groundwater quality impacts.

While some health benefits and WTP for water quality improvements have been partially quantified and/or monetized, those estimates may not fully capture all important water quality-related benefits. Although the following quantifications cannot necessarily be combined with other monetized effects, another way to characterize the benefits is that the final rule is expected to result in a 53 percent reduction in chronic exceedances and a 33 percent reduction in acute exceedances of the national recommended water quality criteria. It is also expected to result in a reduction of up to a 63 percent in the number of immediate receiving water reaches with ambient concentrations exceeding human health criteria for at least one pollutant.

The BCA discusses changes in these potentially important effects qualitatively, indicating their potential magnitude where possible.

XIII. Environmental Justice Impacts

Consistent with the EPA's commitment to advancing environmental justice (EJ) in the Agency's actions, the Agency has analyzed the impacts of this action on communities with EJ concerns and sought input and feedback from stakeholders representing these communities. The EPA has prepared this analysis to implement the recommendations of the Agency's EJ Technical Guidance.[193] For ELG rulemakings, an analysis of EJ impacts is typically conducted as part of the BCA alongside other non-statutorily required analyses such as monetized benefits. However, for this action, the analysis was placed in a standalone EJA document to provide the public with a more detailed discussion of the potential EJ impacts of this action and the initial outreach to communities with potential EJ impacts. The analysis does not form a basis or rationale for any of the actions the EPA is taking in this rulemaking.

Overall, EPA's EJ analysis showed the final rule will reduce differential baseline exposures to pollutants in wastewater and resulting human impacts for population groups of concern when considering potential EJ implications of this regulatory action. E.O. 12898 identifies a number of population groups of concern including minority populations, low-income populations, and Indigenous peoples in the United States and its territories and possessions. In this particular analysis, improvements to water quality, wildlife, and human health resulting from reductions in pollutants in surface water will be distributed more among low-income populations and some people of color under some or all of the regulatory options for this final rule.

Reductions in TTHM concentrations in drinking water and resulting reductions in bladder cancer cases and excess bladder cancer deaths will also be distributed more among communities with EJ concerns under the final rule. Remaining exposures, impacts, and benefits analyzed are small enough that EPA could not conclude whether changes in baseline disproportionate impacts would occur, such as reductions in avoided IQ point losses among children exposed to lead from fish consumption which were estimated to be a total of one avoided IQ point loss across approximately 1.5 million children.

Although the changes in GHGs attributable to the final rule are small compared to worldwide emissions, findings from peer-reviewed evaluations demonstrate that actions that reduce GHG emissions are also likely to reduce climate-related impacts on communities with EJ concerns.

At the national level, upper bound average compliance costs per residential households under the final rule are $3.14 per year. Costs of the final rule in terms of electricity price increases among residential households may impact low-income households and households of color more relative to all households as low-income households and households of color tend to spend a greater proportion of their income on energy expenditures. Despite this, the potential price increases under the upper bound cost scenario represent between less than 0.1 percent and 0.2 percent of energy expenditures for all income, race groups, and income quintiles, and therefore the EPA does not expect costs to have a substantial impact on low-income households and households of color. The methodology and findings of the EJA are described in further detail below.

A. Literature Review

The EPA conducted a literature review to identify academic research and articles on EJ concerns related to coal-fired power plants. The EPA identified eight papers that focused on coal-fired power plants in the United States that were directly relevant to this final rule. The findings of these papers suggest that coal-fired power plants tend to be in poor communities, Indigenous communities, and communities of color. Toomey (2013) reported that 78 percent of African Americans in the United States live within a 30-mile radius of a coal-fired power plant.[194] Impacts discussed in the reports included adverse health impacts resulting from air pollutants (*e.g.,* SO_2, NO_X, $PM_{2.5}$) for those living in proximity to coal-fired power plants, climate justice issues resulting from GHG emissions, and risk of impoundment failures for populations living in proximity to coal waste surface impoundments where coal is mined.[195] [196] [197] All these impacts were found in one or more papers to differentially impact poor communities, Indigenous communities, and communities of color. For further discussion of the literature review, see section 2 of the EJA.

B. Proximity Analysis

The EPA performed proximity analyses to identify and characterize the communities that are expected to be impacted by discharges from steam electric plants via relevant exposure pathways. First, the EPA used geographic information system (GIS) software to map out 1- and 3-mile buffers around each facility. A buffer is a zone that extends a specified distance in every direction from a point on a map. The EPA then assessed potential air impacts within those zones. The 1- and 3-mile distances were chosen to be consistent with the buffer distances

[193] U.S. EPA (Environmental Protection Agency). 2016. *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis.* June. Available online at: *https://www.epa.gov/environmentaljustice/technical-guidance-assessing-environmental-justice-regulatory-analysis.*

[194] Toomey, D. 2013. *Coal Pollution and the Fight for Environmental Justice.* Yale Environment 360. June 19. Available online at: *https://www.e360.yale.edu/features/naacp_jacqueline_patterson_coal_pollution_and_fight_for_environmental_justice.*

[195] Liévanos, R.S., Greenberg, P., Wishart, R. 2018. *In the Shadow of Production: Coal Waste Accumulation and Environmental Inequality Formation in Eastern Kentucky.* Social Science Research, Vol. 71: pp. 37–55.

[196] Israel, B. 2012. *Coal Plants Smother Communities of Color. Scientific American. Available online at: https://www.scientificamerican.com/article/coal-plants-smother-communities-of-color/#:~:text=People%20living%20near%20coal%20plants,percent%20are%20people%20of%20color.*

[197] NAACP (National Association for the Advancement of Colored People). 2012. *Coal Blooded: Putting Profits Before People.* Available online at: *https://www.naacp.org/resources/coal-blooded-putting-profits-people.*

used by the Office of Air and Radiation when performing screening analyses for communities surrounding industrial sources that are expected to be exposed to air emissions (U.S. EPA, 2021a).[198] These are the distances at which air pollution concentrations will be highest before the plume disperses, and an analysis of air impacts with these zones may capture other localized impacts such as air emissions from truck traffic due to changes in activities at steam electric power plants.

Second, the EPA assessed potential impacts in downstream surface waterbodies using 1-, 3-, 50-, and 100-mile buffer distances around each waterbody segment downstream of the initial common identifiers (COMIDs) identified for each effluent discharge. These buffers distances were used to capture impacts to local populations as well as impacts to those traveling to fish or recreate in downstream waterbodies (Sohngen et al, 2015; Sea Grant—Illinois-Indiana, 2018; Viscusi et al., 2008).[199] [200]

Finally, the EPA assessed potential drinking water impacts using information about the service area of PWSs with surface intakes downstream from steam electric power plants.

Overall, the EPA found that 90,000 people live within 1 mile of at least one of the 112 steam electric power plants expected to be affected by the final rule and modeled for the benefits analysis, and about 790,000 people live within 3 miles. When comparing the demographic characteristics of these populations to national demographic characteristics, small exceedances of the national average are observed. Of the population living within 3 miles of a steam electric power plant, the percentage of people identified as low-income is 0.1 percent greater than the national average, and the percent of the population identified as American Indian/Alaska Native and Other living within one and three miles of a steam electric power plant is one percent greater than the national average. The results show relatively greater proportions of people who identify as Asian (non-Hispanic), people who identify as American Indian or Alaska Native (non-Hispanic), and people who identify as Hispanic or Latino.

C. Community Outreach

During the public comment period, the EPA received a comment requesting that the Agency conduct additional outreach with the nine communities identified for outreach during the 2023 proposal. Commenters urged the EPA to not extend the written public comment period and to move forward expeditiously to finalize the proposed rule. Given the time required to plan and conduct the community outreach for the proposed rule (meetings with five of the nine communities were held between May and September 2022, with planning starting in February 2022), the EPA determined that it could not hold additional outreach meetings with all nine communities and also finalize the proposed rule expeditiously, as requested by the commenters. Therefore, the EPA did not hold additional outreach meetings for the final rule. The EPA presents the feedback received from the community outreach meetings conducted for the proposed rule in section 7.5 of the 2023 EJA,[201] which the EPA took into consideration for the final rule.

For the proposed rule, the EPA conducted initial outreach in all nine communities to local environmental and community development organizations, local government agencies, and individual community members involved in community organizing. Between May and September of 2022, EPA was able to meet with community members in five of the identified communities either virtually or in a hybrid format with some in-person participation. The EPA was not able to hold a virtual or hybrid meeting with the remaining four communities. For detailed information of the EPA's community selection methodology, the communities selected, and the structure of the community meetings, see section 7.4 of the 2023 EJA.[202]

The EPA received a broad range of input from individuals in these communities on regulatory preferences, environmental concerns, human health and safety concerns, economic impacts, cultural/spiritual impacts, and ongoing communication/public outreach. Community members also expressed interest in other EPA actions. Two broad themes were conveyed consistently across communities. First, community members identified several perceived harmful impacts from steam electric power plants and conveyed their desire for more stringent regulations to reduce these harmful impacts. Second, community members expressed that more transparency and communication is needed to overcome their decreasing trust in the regulated steam electric power plants and state regulatory agencies and their feelings of skepticism that their communities will be protected from these harmful impacts. In addition to these broad themes, commenters also raised concerns unique to each community. For example, members of the Navajo Nation discussed with the EPA the spiritual and cultural impacts to the community from pollution related to steam electric power plants. In Jacksonville, Florida, community members raised concerns about tidal flows that carry pollution upstream and about storm surges that occur during extreme weather events, causing additional challenges in their community. More detailed summaries of these meetings are presented in section X of the EJA.

The EPA considered all feedback received in these outreach meetings, including feedback on the stringency of potential new regulations and negative impacts experienced as a result of steam electric discharges. The final rule will result in more stringent limitations that will further reduce negative impacts associated with steam electric discharges. The EPA also considered feedback expressing the desire for increased transparency and communication. As discussed in section XIV.C.6, the EPA requiring posting of required reports to a publicly available website to improve transparency. In addition, the EPA recently added a new feature called ECHO Notify to the Enforcement and Compliance History Online (ECHO) website. ECHO Notify provides weekly email notifications of changes to enforcement and compliance data in ECHO. Notifications are tailored to the geographic locations, facility IDs, and notification options that users select. The EPA encourages interested community members to sign up for these alerts. Further information is available at *https://www.echo.epa.gov/tools/echo-notify*. The EPA also encourages individual facilities to work with local communities to foster trust and communication, for example, through text alert systems.

[198] U.S. EPA. 2021a. Regulatory Impact Analysis for Phasing Down Production and Consumption of Hydrofluorocarbons (HFCs) (September). EPA–HQ–OAR–2021–0044–0046.

[199] For this analysis, a downstream waterbody is defined as a segment of water 300 kilometers (~187 miles) downstream of a point of discharge from a steam electric power plant.

[200] Sohngen, B., Zhang, W., Bruskotter, J., & Sheldon, B. (2015). Results from a 2014 survey of Lake Erie anglers. Columbus, OH: The Ohio State University, Department of Agricultural, Environmental and Development Economics and School of Environment & Natural Resources; Sea Grant—Illinois-Indiana (2018). Lake Michigan anglers boost local Illinois and Indiana economies; Viscusi, W.K., Huber, J., & Bell, J. (2008). The economic value of water quality. Environmental and resource economics, 41(2), 169–187.

[201] U.S. Environmental Protection Agency (2023b). *Environmental Justice Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*.

[202] *Ibid.*

D. Distribution of Risks

The EPA evaluated the distribution of pollutant loadings, estimated human health, and estimated environmental impacts resulting from polluted air, surface water, and drinking water. The EPA examined these distributions under both baseline and the regulatory options to identify where current conditions and future improvements may have a differential impact on communities with EJ concerns. The following sections discuss the EPA's methodology and findings.

1. Air

The EPA evaluated air quality impacts in terms of changes in warm season maximum daily average 8-hour (MDA8) ozone and average annual $PM_{2.5}$ concentrations, as described in the BCA. The EPA used the results of the analysis to further evaluate the distribution of air—quality impacts in the EJA to determine whether communities with EJ concerns experience disproportionately high exposures to MDA8 ozone and average annual $PM_{2.5}$ under the baseline and Option B.

The results of the EPA's distributional analysis of air quality impacts indicates that, under the baseline, average annual $PM_{2.5}$ and MDA8 ozone exposures are higher among certain communities with EJ concerns. The EPA found higher exposures for some populations, such as American Indian and Alaska Native (non-Hispanic), Asian (non-Hispanic), and Hispanic populations, relative to their relevant comparison groups. While the regulatory analysis estimating changes in average annual $PM_{2.5}$ and MDA8 ozone exposures shows increases and decreases in pollutant emissions across regions of the United States under the final rule, these changes overall are small and do not change the distribution of air-quality impacts observed under the baseline. Therefore, the EPA concludes that the air-quality changes resulting from the final rule are not expected to mitigate or exacerbate distributional disparities present under the baseline. See section 4.2 of the EJA for more information.

2. Surface Water

Using results from the EA and BCA, the EPA evaluated the distribution of pollutant loadings and the environmental and human health effects of wastewater discharges from steam electric power plants into surface waters into immediate receiving waters. The following sections provide an overview of the EPA's methodology and the results of the EPA's distributional analysis.

a. Immediate Receiving Waters

Using results from the EA, the EPA evaluated the distribution of pollutant loadings and the environmental and human health effects of wastewater discharges from steam electric power plants into immediate receiving waters across communities with EJ concerns. To evaluate the distribution of water quality impacts, the EPA used the IRW model to evaluate water quality impacts by calculating annual average total and dissolved pollutant concentrations in the water column and sediment of immediate receiving waters. It then compares these concentrations to specific water quality criteria values—National Recommended Water Quality Criteria (NRWQC) and Maximum Contaminant Levels (MCLs)—to assess potential impacts to wildlife and human health. To evaluate potential impacts to wildlife, the EPA used the IRW model to estimate bioaccumulation of pollutants in fish tissue of trophic level 3 (T3) and trophic level 4 (T4) fish using the annual average pollutant concentrations in the immediate receiving water. Those results were then compared to benchmark values—threshold effect concentration (TEC) and no effect hazard concentration (NEHC)—to evaluate potential impacts on exposed sediment biota and piscivorous wildlife that consume T3 and T4 fish, respectively. The EPA also used estimated fish tissue concentrations to assess human health impacts—non-cancer and cancer risks—to human populations from consuming fish that are caught in contaminated receiving waters. For a more detailed discussion of the IRW Model see the EA. Information on the socioeconomic characteristics of affected communities was gather from the 2017–2021 ACS dataset and was included with the results from the model to evaluate the distribution of impacts (relative to the baseline) under the final rule.

b. Water Quality, Wildlife, and Human Health Impacts

Based on the results of the distributional analyses of water quality, wildlife, and human health impacts, the EPA determined that under the baseline there were distributional disparities among communities with EJ concerns. Disparities were most often observed among populations such as African American (non-Hispanic) or American Indian or Alaska Native (non-Hispanic) populations when comparing the percent of the population affected in communities with immediate receiving waters benchmark exceedances to the national average and to communities with immediate receiving waters without benchmark exceedances. This, along with distributional disparities observed under the baseline for other populations, indicates the presence of potential EJ concerns under the baseline across the three analyses. Analyzing the impacts of final rule across the analyses, the EPA found that the final rule reduced the amount of immediate receiving waters with benchmark exceedances and the population affected by these exceedances. However, in each of the analyses the EPA found that while the final rule mitigated distributional disparities identified under the baseline for communities with EJ concerns, remaining immediate receiving waters with exceedances under the final rule were more concentrated in other communities with EJ concerns. EPA found particular concentration for American Indian or Alaska Native populations relative to the baseline. See section 4.2 of the EJA for more information.

c. Downstream Waters

Using the results from the downstream analysis performed in the BCA, the EPA further evaluated the downstream surface water impacts in the EJA to determine whether communities with EJ concerns experience a differential share of noncancer health effects from exposure mercury through consuming fish in contaminated downstream surface waters.

The results of the EPA's analysis showed potential EJ concerns in the baseline in terms of differential and adverse impacts in communities with EJ concerns. Differential and adverse impacts were concentrated among infants of color (*e.g.,* Hispanic, Asian [non-Hispanic], and Other [non-Hispanic]) and infants below the poverty level of mothers consuming fish at recreational and subsistence rates relative to White children and children not below the poverty line, respectively. For both cohorts, under the final rule, increases in avoided IQ point losses were estimated relative to the baseline across all racial or ethnic groups and income groups. These estimated increases were too small to substantially change the distribution of IQ points relative to the baseline among infants of color and among infants below the poverty level. See section 4.3 of the EJA for more information.

The EPA also evaluated human health endpoints related to lead and arsenic exposures from fish consumption. As shown in the BCA, avoided IQ point losses in children and avoided cardiovascular deaths (CVD) in adults

from reductions in fish tissue concentrations of lead, as well as reductions in annual skin cancer cases in adults from reductions in fish tissue concentrations of arsenic estimated under the final rule were negligible (*e.g.,* a total avoided IQ point loss of one point across 1,555,558 exposed children). Therefore, the EPA determined that reporting fractional distributional changes by racial or ethnic groups and income groups for the affected population would not be informative. See section 4.3 of the EJA for more information.

3. Drinking Water

Using the results from the drinking water analysis performed in the BCA, the EPA further evaluated downstream drinking water impacts in the EJA to determine whether communities with EJ concerns served by potentially affected drinking water systems experience a differential share of bladder cancer cases from exposure to TTHM. In the BCA, the EPA modeled baseline incremental TTHM concentrations and bladder cancer cases attributable to steam electric discharges.[203] Since the EPA evaluated only the changes in TTHM concentrations and avoided bladder cancer cases and deaths attributable to steam electric discharges in the BCA, in this analysis, the EPA only evaluated whether the distribution of exposures and health effects indicated potential EJ concerns under the incremental changes resulting from the regulatory options.

The results of the EPA's analysis of changes in TTHM concentrations and resulting changes in bladder cancer cases and deaths from consuming drinking water with TTHM shows that the final rule reduces TTHM concentrations and reduces the incidence of bladder cancer cases and excess bladder cancer deaths in states with affected drinking water systems. Across the analyses, under the final rule, the majority of states with affected systems serve communities with at least one demographic group (*i.e.,* low-income or person of color) above the national average, with the largest proportion of these states having two demographic groups above the national average. Analyzing the distribution of changes across the analyses and regulatory options, the EPA finds that states with affected systems serving communities with one demographic group above the national average experience the largest median changes in TTHM concentrations and avoided bladder cancer cases and excess bladder cancer deaths than states serving communities with two and three or more demographic groups above the national average, respectively. While the magnitude of the median change observed across the analyses decreases in communities with one, two, or three or more demographic groups above the national average, the EPA finds that this is not due to there being smaller reductions in TTHM concentrations and avoided bladder cancer cases and excess bladder cancer deaths, but rather that these states generally have more systems experiencing smaller changes. See section 4.4. of the EJA for more information.

E. Distribution of Benefits and Costs

The EPA examined the estimated benefits and costs of the final rule for potential differences in how they are distributed across affected communities, in addition to evaluating the distribution of exposures and health impacts discussed above. Office of Management and Budget (OMB) Circular A–4, which implements E.O. 12866, states that regulatory analyses should analyze distributional effects which Circular A–4 defines as ''how the benefits and the costs of a regulatory action are ultimately experienced across the population and economy, divided up in various ways (*e.g.,* income groups, race or ethnicity, gender, sexual orientation, disability, occupation, or geography; . . .).'' As discussed below, EPA research demonstrates that climate change impacts associated with GHG reductions that are modeled to occur under this rule are likely to accrue to communities with EJ concerns but other benefits and costs under the final rule may not have substantial impacts.

The EPA began its evaluation of benefits with a screening of the benefits categories. For Option B, at both three percent and seven percent discount rates, approximately 99 percent of monetized benefits accrued from reductions in air pollution due to estimated shifts in electric generation resulting from the incremental costs of the final rule. Furthermore, these air benefits were always comprised of approximately a 3-to-1 ratio of conventional air pollutant health benefits to GHG benefits (see section 8 of the BCA for more information on air emissions and benefits).[204] Thus, while the EPA evaluated a number of exposures and endpoints for disproportionate baseline impacts, the Agency screened these two benefit categories through this initial comparison for further evaluation.

With respect to GHG benefits, scientific assessments and Agency reports produced over the past decade by the U.S. Global Change Research Program,[205] the Intergovernmental Panel on Climate Change,[206] [207] [208] [209] [210] and the National Academies of Science, Engineering, and Medicine [211] [212] provide evidence that the impacts of climate change raise potential EJ concerns. These reports conclude that poorer communities or communities of color can be especially vulnerable to climate change impacts because they tend to have limited adaptive capacities, are more dependent on climate-sensitive resources such as local water and food supplies or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/

[203] Background TTHM concentrations and bladder cancer cases attributable to sources other than steam electric discharges were not modeled under the baseline but would not impact the analysis of incremental changes as discussed in the BCA.

[204] EPA scaled the air benefits to other regulatory options based on total costs.

[205] USGCRP. 2016. *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins,* Balbus, A., Gamble, J., Beard, C., Bell, J., Dodgen, D., Eisen, R., Fann, N., Hawkins, M., Herring, S., Jantarasami, L., Mills, D., Saha, S., Sarofim, M., Trtanj, J., Ziska, L. Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. Available online at: *https://www.dx.doi.org/10.7930/J0R49NQX.*

[206] USGCRP. 2018. *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment.* U.S. Global Change Research Program. Available online at: *https://pp.doi.org/10.7930/NCA4.2018.*

[207] Porter, J, Xie, L., Challinor, A., Cochrane, K., Howden, S., Iqbal, M., Lobell, D., Travasso, M. 2014. *Food security and food production systems. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability.* Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change pp. 485–533.

[208] Oppenheimer, M., Campos, M., Warren, R., Birkmann, J., Luber, G., O'Neill, B., Takahashi, K. 2014. *Emergent risks and key vulnerabilities.* Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. pp. 1039–1099.

[209] Smith, K, Woodward, A., Campbell-Lendrum, D., Chadee, D., Honda, Y., Liu, Q., Olwoch, J., Revich, B., Sauerborn, R. 2014. *Human health: impacts, adaptation, and co-benefits.* Climate Change 2014. Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change pp. 709–754.

[210] IPCC (Intergovernmental Panel on Climate Change), 2018. *Global Warming of 1.5°C, An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty.*

[211] National Research Council. 2011. *America's Climate Choices.* Available online at: *https://www.doi.org/10.17226/12781.*

[212] NASEM. 2017. *Communities in Action: Pathways to Health Equity.* Available online at: *https://www./doi.org/10.17226/24624.*

racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the United States.

The EPA recently conducted a peer-reviewed analysis of the distribution of climate change impacts. EPA (2021) [213] evaluated the disproportionate risks to communities with EJ concerns. The EPA looked at factors including age, income, education, race, and ethnicity associated with six impact categories: air quality and health, extreme temperature and health, extreme temperature and labor, coastal flooding and traffic, coastal flooding and property, and inland flooding and property. The EPA calculated risks for each demographic group relative to its ''reference population'' (all individuals outside of each group) for scenarios with 2°C of global warming or 50 centimeters of sea level rise. The estimated risks were based on current demographic distributions in the contiguous United States. EPA (2021) includes findings that the following groups are more likely than their reference population to currently live in areas with:

- The highest increases in childhood asthma diagnoses from climate-driven changes in $PM_{2.5}$ (low-income, Black and African American, Hispanic and Latino, and Asian populations);
- The highest percentage of land lost to inundation (low-income and American Indian and Alaska Native populations);
- The highest increases in mortality rates due to climate-driven changes in extreme temperatures (low-income and Black and African American populations);
- The highest rates of labor hour losses for weather-exposed workers due to extreme temperatures (low-income, Black and African American, American Indian and Alaska Native, Hispanic and Latino, and Pacific Islander populations);
- The highest increases in traffic delays associated with high-tide flooding (low-income, Hispanic and Latino, Asian, and Pacific Islander populations); and
- The highest damages from inland flooding (Pacific Islander populations).

For further discussion of the impacts analyzed in U.S. EPA (2021) and other peer-reviewed evaluations, see section 5.1 of the EJA.

The EPA notes that the changes in GHG emissions attributable to the final rule are relatively small compared to worldwide emissions. Nevertheless, the findings of peer-reviewed evaluations demonstrate that actions that reduce GHG emissions are likely to reduce climate impacts on communities with EJ concerns. Findings demonstrate particular reductions in climate impacts for communities of color and low-income communities.

With respect to conventional air pollutant health benefits, the current EPA modeling methodology results in benefits that are proportional to exposures. In other words, the distributional findings of air pollutant exposures discussed above are the same findings the EPA has for this benefit category: exposure and health benefit improvements and degradations attributable to this final rule will be proportionately experienced by all communities evaluated. However, there are several important nuances and caveats to this conclusion owing to differences in vulnerability and health outcomes across demographic groups. For example, there is some information suggesting that the same $PM_{2.5}$ exposure reduction will reduce the hazard of mortality more so in Black populations than in White populations.[214] [215] In addition, demographic-stratified information relating $PM_{2.5}$ and ozone to other health effects and valuation estimates is currently lacking.

With respect to costs, the EPA notes that the impacts on ratepayers will depend on the degree to which compliance costs are passed through to electricity consumers via higher electricity rates. In general, lower-income households spend less, in the absolute, on energy than higher-income households, but energy expenditures represent a larger share of their income. Therefore, electricity price increases tend to have a relatively larger effect on lower-income households. Further discussion of these disparities is provided in section 5.2 of the EJA. The EPA estimated the potential impacts of incremental ELG compliance costs on households' utility bills based on average electricity consumption and assuming a worst-case scenario where all costs are passed through to consumers. The EPA estimated that the final rule (Option B) corresponds to an average increase of $3.14 per household per year, with a range of $0.19 to $5.44 per year across NERC regions. These cost increases are too small [216] to indicate the potential for significant direct impacts to household electricity consumers.[217]

XIV. Regulatory Implementation

A. Continued Implementation of Existing Limitations and Standards

The EPA has continually stressed, since the announcement of this supplemental rulemaking, that the existing 40 CFR part 423 limitations and standards in effect continue to apply.[218] In the sections below, the EPA discusses considerations for permitting authorities and regulated entities as they continue to implement existing regulations and look ahead to the regulations finalized.

1. Facilities Must Still Continue To Be Permitted for, and Meet, the 2020 Rule Limitations

The EPA reaffirms that permitting authorities must continue to write permits that include existing 2015 and 2020 rule BAT limitations as applicable, whether as part of permit renewals or as part of permit modifications. Similarly, permittees must meet applicable permit limitations as soon as possible. The Agency has not issued a postponement rule for the 2020 rule FGD wastewater and BA transport water BAT limitations as it did in 2017 for the 2015 rule. And as discussed in section VII of this preamble, the EPA is retaining the 2020 FGD wastewater and BA transport water limitations and affirms that the technologies on which they are based are available and achievable, as an interim step toward meeting the final zero-discharge requirements in this rule.

Since the EPA did not postpone the earliest compliance dates in the 2020 rule,[219] which have since passed, permitting authorities should not establish an ''as soon as possible'' date that is anything other than as soon as

[213] U.S. EPA (Environmental Protection Agency). 2021. *Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts.* EPA 430–R–21–003.

[214] U.S. EPA (Environmental Protection Agency). 2019. *Integrated Science Assessment (ISA) for Particulate Matter (Final Report).* December. EPA/600/R–19/188. Available at: *https://www.epa.gov/naaqs/particulate-matter-pm-standards-integrated-science-assessments-current-review.*

[215] U.S. EPA (Environmental Protection Agency). 2022. *Supplement to the 2019 Integrated Science Assessment for Particulate Matter (Final Report).* May. EPA/600/R–22/028. Available at: *https://www.epa.gov/isa/integrated-science-assessment-isa-particulate-matter.*

[216] While the incremental burden relative to income is not distributionally neutral, *i.e.,* any increase would affect lower-income households to a greater extent than higher-income households, the final rule is expected to have a very small impact in the absolute across all regions analyzed which is also small relatively as the potential price increase is between less than 0.1 percent and 0.2 percent of energy expenditures for all income and race groups, and between less than 0.1 percent and 0.5 percent of just *electricity* expenditures for all but the bottom quintile income group in the most impacted NERC region.

[217] EPA notes that other electricity consumers (*e.g.,* industrial consumers) could also face increased electricity prices.

[218] 86 FR 41801 (August 3, 2021).

[219] Compliance dates for FGD wastewater and BA transport water in the 2020 rule were as soon as possible beginning October 13, 2021.

possible to comply with the 2020 limitations. In some cases, although unlikely at the time of this publication, a facility may still not have a permit incorporating the 2015 or 2020 rule BAT requirements. In such circumstances, a permitting authority must still include these limitations with the appropriate ''as soon as possible'' date. For example, suppose a permit applicant's permit still has the 1982 limitations; the applicant submits a permit modification request prior to this final rule effective date, but the permitting authority has not yet issued a modified permit. Here, the permitting authority may not simply issue the facility a permit incorporating this final zero-discharge limitations with a ''no later than'' date of 2029. Instead, the permittee is still obligated to meet the 2020 rule limitations no later than December 31, 2025. Note that, without the 2020 rule limitations in a permit, a facility may not participate in the permanent cessation of coal combustion by 2034 subcategory.

2. Permitting Site-Specific Technology-Based Effluent Limitations Through BPJ Analysis

At proposal, the EPA reaffirmed that BAT limitations were currently required to be developed on a BPJ basis by permitting authorities for discharges of both CRL and legacy wastewater. Some commenters contended that this outcome is improper because it does not constrain the permitting authority from selecting surface impoundments as BAT. The EPA disagrees. In *Southwestern Electric Power Co.* v. *EPA,* the Fifth Circuit stopped short of prohibiting any future selection of surface impoundments as the commenters stated. Instead, the Court held that the Agency's actions in selecting surface impoundments as BAT for legacy wastewater and CRL was arbitrary and capricious or inconsistent with the statute based on EPA's stated rationale. In particular, the Court faulted the EPA for not offering any rationale as to why surface impoundments were BAT, using the statutory factors. *See Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1018 n.20 (''[T]he record fails to explain why impoundments are BAT, if that term is to have any meaning. Furthermore, if chemical precipitation or biological treatment are technically feasible but simply too costly for treating legacy wastewater, the EPA could have said so.''); *id.* at 1025 (''The rule pegs BAT for leachate to the decades-old BPT standard, without offering any explanation for why that prior standard is now BAT. That is flatly inconsistent with the Act's careful distinction between the two standards.''). Permitting authorities performing a BPJ analysis are required to consider the statutory factors and determine what technologies are available, are economically achievable, and have acceptable non-water quality environmental impacts. Thus, permitting authorities would also be prohibited from defaulting to surface impoundments without explaining why surface impoundments represent BAT, as that term is used in the CWA. Instead, they must perform a thorough BPJ analysis that considers technologies beyond surface impoundments (including, presumably, the technologies described in this record) to identify the technology that represents BAT. The EPA does not rule out the possibility that circumstances at a facility will lead the permitting authority to select surface impoundments as BAT. However, this would only occur where a permitting authority can demonstrate that surface impoundments meet the BAT statutory factors, a tough hurdle for a treatment technology that has been found not to remove dissolved pollutants. *Id.* at 1026 (''To be sure, we do not say that EPA is precluded by the Act from ever setting BAT equivalent to a prior BPT standard. But given the plain distinction between the two standards market out in the Act, the agency would at least have to offer some explanation for its decision that speaks to the statutory differences between BAT and BPT.'').

Furthermore, the EPA received comments that certain state laws prohibit permitting authorities in those states from imposing BAT limitations more stringent than any national regulations. EPA disagrees that this poses an implementation challenge. The EPA has not established BAT based on surface impoundments, but rather, in some cases, reserved BAT limitations to be developed by permitting authorities using their BPJ. And the requirement for BPJ is to perform a thorough analysis to select the technology that represents BAT at a particular site. Thus, to the extent that a permitting authority determines a more stringent technology represents BAT at a particular site, this would not be inconsistent with the state laws cited.

3. Reopening Permits for CRL and Legacy Wastewater

At proposal, the EPA recommended, but did not require, that any permit issued or modified between the proposal and the final rule contain a reopener clause in accordance with 40 CFR 122.62(a)(7) and 124.5. Permitting authorities that included this provision should consider reopening these portions of existing permits as soon as practicable after July 8, 2024.

B. Implementation of New Limitations and Standards

The limitations and standards in this final rule apply to discharges from steam electric power plants through incorporation into NPDES permits issued by the EPA and authorized states under CWA section 402, and through pretreatment programs under CWA section 307. NPDES permits and pretreatment control mechanisms issued after July 8, 2024, must incorporate the ELGs, as applicable. Also, under CWA section 510, states can require effluent limitations under state law as long as they are no less stringent than the requirements of any final rule. Finally, as well as requiring application of the technology-based ELGs in any final rule, CWA section 301(b)(1)(C) requires the permitting authority to impose more stringent effluent limitations, as necessary, to meet applicable water quality standards. Relevant water quality-based considerations are discussed in section XIV.D.

1. Availability Timing of Final Rule Requirements

The direct discharge limitations in this rule apply only when implemented in an NPDES permit issued to a discharger. Under the CWA, the permitting authority must incorporate these ELGs into NPDES permits as a minimum level of control. The final rule provides the plant's permitting authority with discretion to determine the date when the new effluent limitations for FGD wastewater, BA transport water, and CRL would apply to a given discharger. For zero discharge requirements for FGD wastewater, BA transport water, and CRL, as well as the chemical precipitation-based requirements for unmanaged CRL, the limitations in this final rule become applicable by a date that is as soon as possible after July 8, 2024, but in no case later than December 31, 2029.

For dischargers subject to less stringent FGD wastewater and BA transport water limitations based on certifications that they qualify for a subcategory based on permanent cessation of coal combustion, the EPA is requiring permitting authorities to put in tiered limitations after the permanent cessation of coal combustion. For the permanent cessation of coal combustion by 2028 subcategory, the final rule contains a tiered set of limitations applicable following December 31, 2028:

- The first tier of these limitations is composed of zero-discharge limitations

for FGD wastewater and BA transport water after April 30, 2029. These limitations would apply if the EGU had in fact permanently ceased coal combustion by December 31, 2028, as the plant represented it would. As suggested in public comments, this date is 120 days after the permanent cessation of coal combustion date, allowing for facilities to complete any necessary residual discharges.[220]

- The second tier is composed of zero-discharge limitations for these same wastewaters after December 31, 2028. If a plant fails to cease combustion of coal by 2028, as it represented it would, for any reason other than those specified in § 423.18, these zero-discharge limitations would automatically apply.

For the permanent cessation of coal combustion by 2034 subcategory, the final rule contains a tiered set of limitations applicable following December 31, 2034:

- The first tier of these limitations is composed of zero-discharge limitations for FGD wastewater and BA transport water after April 30, 2035. These limitations would apply if the EGU had in fact permanently ceased coal combustion as it represented it would.
- The second tier is composed of zero-discharge limitations for the same wastewaters, as well as CRL, after December 31, 2034. If a plant fails to cease combustion of coal by 2034, as it represented it would, for any reason other than those specified in § 423.18, these zero-discharge limitations would automatically apply.

This final rule does not affect dischargers choosing to meet the 2020 VIP effluent limitations for FGD wastewater; the date for meeting those limitations is December 31, 2028. Similarly, where a facility has elected to participate in the subcategory for permanent cessation of coal combustion by December 31, 2028, the final rule allows for the zero-discharge limitations for FGD wastewater and BA transport water to be met as late as December 31, 2029, and is not designed to impose these zero-discharge limitations prior to the tiered zero-discharge limitations established for that subcategory.[221]

Pretreatment standards, unlike effluent limitations, are directly enforceable and must specify a time for compliance not to exceed three years from the date of promulgation under CWA section 307(b)(1). Under the EPA's General Pretreatment Regulations for Existing and New Sources, POTWs with flows in excess of five MGD must develop pretreatment programs meeting prescribed conditions.[222] These POTWs have the legal authority to require compliance with applicable pretreatment standards and control the introduction of pollutants to the POTW through permits, orders, or similar means. POTWs with approved pretreatment programs act as the control authorities for their industrial users. Among the responsibilities of the control authority are the development of the specific indirect discharge limitations for the POTW's industrial users. Because pollutant discharge limitations in categorical pretreatment standards may be expressed as concentrations or mass limitations, in many cases, the control authority must convert the concentration- or mass-based limitations applicable to a specific industrial user and then include these in POTW permits or another control instrument.

Regardless of when a plant's NPDES permit is ready for renewal, the EPA recommends that each plant immediately begin evaluating how it intends to comply with the requirements of the final rule. In cases where significant changes in operation are appropriate, the EPA recommends that the plant discuss such changes with its permitting authority and evaluate appropriate steps and a timeline for the changes as soon as possible, even before the permit renewal process begins.

The ''as soon as possible'' date is the effective date of any final rule, unless the permitting authority determines another date after receiving relevant information submitted by the discharger.[223] The final rule does not revise the specified factors permitting authorities must consider in determining the as soon as possible date under the 2015 and 2020 rules. Based on receiving relevant information from the discharger, the NPDES permitting authority may determine a different date is ''as soon as possible'' within the implementation period, using the factors below:

- Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final rule.
- Changes being made or planned at the plant in response to GHG regulations for new or existing fossil fuel-fired plants under the CAA, as well as regulations for the disposal of coal combustion residuals under subtitle D of RCRA.
- For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment.
- Other factors as appropriate.

The ''as soon as possible'' date determined by the permitting authority may or may not be different for each wastestream. The NPDES permitting authority should provide a well-documented justification of how it determined the ''as soon as possible'' date in the fact sheet or administrative record for the permit. If the permitting authority determines a date later than the effective date of the final rule, the justification should explain why allowing more time to meet any final limitations is appropriate, and why the discharger cannot meet the effluent limitations as of the effective date.

2. Conducting BPJ Analyses for Discharges of CRL and Legacy Wastewater

For some CRL and legacy wastewaters, the EPA is reserving BAT limitations to be determined on a case-by-case basis using the permitting authority's BPJ. The factors considered by the permit writer in a BPJ analysis are the same as those that EPA considers in establishing technology-based effluent limitations. *See* 40 CFR 125.3(d)(1) through (3). Thus, a permitting authority may not default to any technology (for example, surface impoundments) in selecting BAT, nor may a permitting authority fail to develop technology-based effluent limitations and instead simply calculate water quality-based effluent limitations. Instead, a permitting authority is required to determine limitations based on the BAT.[224]

Consideration of Leasing. Leasing is an option offered by commercial vendors. In some cases, it may be possible to lease various pollution treatment technologies for a timeframe shorter than the timeframes considered in this rule's primary evaluation. In

[220] The EPA notes that these do not include discharges of legacy wastewaters from surface impoundments closing under the CCR rule, which are covered by different regulatory provisions.

[221] In contrast, the subcategory for EGUs permanently ceasing coal combustion by December 31, 2028, does not cover discharges of CRL, and thus discharges of CRL would be permitted in accordance with limitations in the subcategory for EGUs permanently ceasing coal combustion by December 31, 2034.

[222] *See, e.g.,* 40 CFR 403.8(a).

[223] Information in the record indicates that most facilities should be able to complete all steps to implement changes needed to comply with the BA transport water requirements within 32 to 35 months, the FGD wastewater requirements within 28 months, and the CRL requirements within 22 months (DCN SE08480, SE10289).

[224] In doing so, permitting authorities may consider relevant information such pollution treatment technologies already in operation at the facility and the information contained in this record on the performance and costs of various technologies.

some cases, shorter duration leases might be more costly; however, where the record precluded the EPA from establishing a nationwide BAT, it is possible that site-specific considerations may make leased equipment economically achievable for a given facility, and thus a relevant consideration in a BPJ analysis.

Consideration of Closure Deadlines Pursuant to the CCR Rule. For certain legacy wastewater, the EPA declined to establish a nationwide BAT, in part, due to the tight closure timeframes for CCR surface impoundments under the CCR rule. The EPA cannot evaluate the precise stage of closure each CCR surface impoundment would be in at the time of its permit issuance or renewal and whether continuation with that stage of closure would be compatible with the operation of any specific technology. In contrast, permitting authorities can do this through the BPJ process after gathering relevant information through the permit application or permit modification. This may require examination of the site-specific closure plan required under the CCR rule and any additional details regarding the ongoing closure process that are not contained in the closure plan itself.

3. Conforming Changes to § 423.18

The EPA is making two changes to § 423.18. First, the EPA is including the new permanent cessation of coal combustion by 2034 subcategory in the permit conditions of § 423.18. When an EGU proceeds towards permanent cessation of coal combustion under the new subcategory, if that EGU is involuntarily forced to burn coal beyond December 31, 2034, it may qualify for the same protections as an EGU in the permanent cessation of coal combustion by 2028 subcategory.

Second, the EPA is clarifying that an Energy Emergency Alert (EEA) is a valid order under § 423.18(a)(3) to qualify for this provision. The purpose of an EEA is to provide real-time indication of potential and actual energy emergencies within an interconnection.[225] The EPA received comment about these alerts specifically in the context of the CAA section 111 proposed rule. These are short-duration reliability events similar to the types explicitly listed in § 423.18, and this clarification is not meant to limit the use of § 423.18, but rather to ensure that it operates as intended: to allow an EGU to operate for reliability purposes without violating its CWA permit.

4. Information To Assist in Permitting Discharges of Unmanaged CRL

At proposal, the EPA provided a recommended list of information that could be provided to a permitting authority to determine whether a discharge of CRL through groundwater constituted the FEDD from a point source into a WOTUS. The EPA also solicited comment on including provision of this information as a regulatory requirement or otherwise obtaining the data (*e.g.,* through a CWA section 308 request). The EPA received a wide range of comment on this solicitation, but on November 20, 2023, the Agency published a draft guidance titled *Applying the Supreme Court's County of Maui* v. *Hawaii Wildlife Fund Decision in the Clean Water Act section 402 National Pollutant Discharge Elimination System Permit Program to Discharges through Groundwater.* The draft guidance describes the *Maui* decision's functional equivalent analysis and explains the types of information that may be relevant to determining which discharges through groundwater require coverage under an NPDES permit. This guidance will assist permitting authorities, the regulated community, and other stakeholders in appropriately applying the ''functional equivalent'' standard in the NPDES permits program and is a more appropriate instrument for addressing this particular implementation issue. The EPA intends to issue revised guidance on this topic soon. For further information visit: *https://www.epa.gov/npdes/releases-point-source-groundwate*r.

C. Reporting and Recordkeeping Requirements

The EPA is finalizing several new or modified reporting and recordkeeping requirements in § 423.19, pursuant to authority under CWA sections 304(i) and 308. First, the EPA is including additional provisions for the annual progress reports required for EGUs permanently ceasing coal combustion by 2028. Second, the EPA is including reporting and recordkeeping requirements for the new subcategory of EGUs permanently ceasing coal combustion by 2034. Third, the EPA is including reporting and recordkeeping requirements for the subcategory for EGUs with certain discharges of unmanaged CRL. Fourth, the EPA is including reporting and recordkeeping requirements for facilities making use of the definitional changes with respect to necessary discharges of FGD wastewater, BA transport water or CRL during high intensity, infrequent storm events. Fifth, the EPA is including a one-year flexibility for EGUs that have installed zero-discharge systems to support their transition to zero discharge by allowing necessary discharges of permeate or distillate subject to reporting and recordkeeping requirements. Finally, the EPA is requiring this and all other reporting to be posted to a publicly available website.

1. Summary of Changes to the Annual Progress Reports for EGUs Permanently Ceasing Coal Combustion by 2028

The EPA is modifying the annual progress reports for the subcategory of EGUs permanently ceasing coal combustion by 2028, as it proposed it would. Specifically, the EPA is adding a requirement that the annual progress reports include either the official filing to the facility's reliability authority or a certification providing an estimate of when such a filing will be made. Furthermore, the EPA is requiring that the final annual progress report prior to permanent cessation of coal combustion must include the official filing. While facilities may already include these filings in the NOPP or annual progress reports, these filings were not explicitly required in the 2020 rule and provide the strongest assurance that a facility will not voluntarily change its plans and continue discharging beyond 2028.

2. Summary of the Reporting and Recordkeeping Requirements for EGUs Permanently Ceasing Coal Combustion by 2034

The EPA is including new reporting and recordkeeping requirements for EGUs permanently ceasing coal combustion by 2034, including an initial NOPP and annual progress reports, as it proposed it would. Consistent with the requirements for EGUs permanently ceasing coal combustion by 2028, the EPA is requiring that the initial NOPP contain several items. A NOPP shall include the expected date that each EGU is projected to achieve permanent cessation of coal combustion, whether each date represents a retirement or a fuel conversion, whether each retirement or fuel conversion has been approved by a regulatory body, and what the relevant regulatory body is. In addition, the NOPP shall include the most recent integrated resource plan for

[225] An EEA-Level 1 occurs when the ISO/RTO has enough power to meet demand but not enough backup resources. An EEA-Level 2 occurs when the ISO/RTO anticipates interruption of service and takes steps to avoid power outages by requesting outside help to meet requirements including consumers being asked to conserve energy. An EEA-Level 3 occurs when an ISO/RTO is energy deficient and operating with reserves below the required minimum. At level 3, utilities curtail energy use through controlled service interruptions.

which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, or other documentation supporting that the electric generating unit will permanently cease the combustion of coal by December 31, 2034. The NOPP shall also include, for each such EGU, a timeline to achieve the permanent cessation of coal combustion. Each timeline shall include interim milestones and the projected dates of completion. Finally, the NOPP shall include, for each such EGU, a certification statement that the facility is in compliance with the FGD wastewater and BA transport water limitations of the 2020 rule. Because the NOPP requires a certification statement that the facility is in compliance with the FGD wastewater and BA transport water limitations of the 2020 rule, which could have applicability dates as late as December 31, 2025, EPA has finalized that date as the date for submitting the NOPP.

The EPA is also requiring an annual progress report for facilities in this subcategory. An annual progress report shall detail the completion of any interim milestones listed in the NOPP since the previous progress report, provide a narrative discussion of any completed, missed, or delayed milestones, and provide updated milestones. An annual progress report shall also include one of the following:

- A copy of the official suspension filing (or equivalent filing) made to the facility's reliability authority detailing the conversion to a fuel source other than coal;
- A copy of the official retirement filing (or equivalent filing) made to the facility's reliability authority which must include a waiver of recission rights; or
- An initial certification, or recertification for subsequent annual progress reports, containing a statement that the facility will make one of the other filings.

The certification or recertification must include the estimated date that such a filing will be made. Furthermore, the EPA is requiring that the final annual progress report must include the actual filing to the reliability authority. Thus, the final annual progress report cannot include a certification statement.

3. Summary of Reporting and Recordkeeping Requirements for Certain Discharges of Unmanaged CRL

As discussed in section VII of this preamble, CRL can be discharged not only through end-of-pipe discharges, but also through groundwater, and the EPA is establishing BAT limitations for a subcategory of EGUs that includes EGUs with discharges of CRL that a permitting authority determines are the FEDD of CRL to a WOTUS. The EPA is including annual reporting and recordkeeping requirements to facilitate the permitting authorities' review of such discharges. These requirements also facilitate compliance monitoring and make compliance information available to the public.

As it proposed it would, the EPA is requiring that facilities with discharges of CRL that a permitting authority determines are the FEDD of CRL to a WOTUS file an annual combustion residual leachate monitoring report with the permitting authority. This annual reporting requirement would be implemented via NPDES permits that cover one or more FEDD of CRL to a WOTUS through groundwater. The EPA is requiring that this report provide a comprehensive set of monitoring data. The EPA is including this requirement to facilitate permitting authorities' ability to determine compliance with CRL limitations and to increase transparency to local communities. Thus, in addition to the data provided under 40 CFR part 127, where an EGU is determined to have a FEDD of CRL, the EPA is requiring groundwater monitoring data on the CRL leaving each landfill or surface impoundment and where it enters surface waterbodies. The EPA is also requiring the report to include monitoring data on all the pollutants treated by chemical precipitation, not just mercury and arsenic, the two indicator pollutants.

4. Certification for Necessary Discharges of FGD Wastewater, BA Transport Water, or CRL During High Intensity, Infrequent Storm Events

At proposal, the EPA solicited comment on a number of topics concerning stormwater mixed with regulated process wastewaters, as well as comment on any necessary, related reporting and recordkeeping requirements. As discussed in section VII.B.5 of this preamble, the EPA is finalizing a definitional change for wastewater resulting from certain high intensity, infrequent storm events. As part of this change, the EPA is requiring a certification that includes several pieces of information that will assure the permitting authority and the public that the discharge is necessary and does not violate any other permit requirements. First, the certification shall include a statement that the facility experienced a storm event exceeding a 10-year, 24-hour or longer duration, including specifics of the actual storm event that are sufficient for a third party to verify the accuracy of the statement. Second, the certification shall include a statement that the discharge of low volume wastewater that would otherwise meet the definition of FGD wastewater, BA transport water, or CRL was necessary, including a list of the best management practices at the site and a narrative discussion of the ability of on-site equipment and practices to manage the wastewater. Third, the certification statement shall include the duration and volume of any such discharge. Finally, the certification statement shall include a statement that the discharge does not otherwise violate any other limitation or permit condition.

5. One-Year Flexibility for Any Necessary Discharges of Permeate or Distillate From Newly Operational FGD Wastewater or CRL Treatment Systems

The EPA anticipates that some plants seeking to meet the final zero-discharge limitations for FGD wastewater or CRL may install one or more technologies that produce a distillate or permeate following treatment. The EPA's technology basis incorporates a process by which the plant will recycle such distillate or permeate within the plant to achieve zero discharge. At proposal, however, the EPA solicited comment on the propriety of a limited flexibility that would allow some time for a plant to optimize its zero-discharge system to fully achieve zero discharge, subject to a reporting requirement. Importantly, for plants seeking this flexibility, a permitting authority would not include this optimization period in the calculation of the plant's ''as soon as possible'' date for meeting the FGD wastewater or CRL limitations. A plant given this flexibility would monitor and report any necessary discharges of permeate or distillate over the first year of attempted zero discharge, while the system was being optimized, and these discharges would not be a violation of the otherwise applicable zero-discharge requirements. For subsequent years, the flexibility would be discontinued.

The EPA received few comments on this solicitation, but those that were received favored the additional flexibility. On the timeframe, the EPA received comments suggesting that one or two years might be appropriate for such a flexibility. One commenter specifically discussed steps for optimizing an initial stage chemical precipitation system that could take up to two years.

The EPA agrees with commenters that the flexibility is warranted, but disagrees that two years is appropriate. In discussions with technology vendors,

the EPA learned that new pollution control technology operators at a facility are most likely to seek vendor support during the first year of operations. Even the comment suggesting a two-year timeframe conceded, ''Commercially proven technology designs generally take a full year to optimize.'' During this optimization process, even with the flexibility to discharge permeate or distillate when necessary, the zero-discharge treatment technology will still result in significant additional pollutant removals which will only be improved upon once the optimization is complete and the permeate or distillate may no longer be discharged. The NSPS limitations established in the 2015 rule and the BAT limitations in the 2020 rule's VIP (which were developed using data from thermal evaporation systems' distillate and membrane filtration systems' permeate, respectively) result in more pollutant removals than either chemical precipitation alone or chemical precipitation plus biological treatment. By expressly allowing plants a period for optimization, and removing this optimization consideration that would otherwise allow for delayed availability timing under § 423.11(t)(3), this flexibility will also facilitate the transition to zero discharge by reducing the amount of time it would take for plants to begin full-scale use of their pollutant treatment systems. Therefore, the EPA is finalizing a flexibility in § 423.18 to allow discharges of distillate or permeate from a newly operational FGD wastewater or CRL treatment system, where necessary, in the first year of operations.

The necessary discharges included in this flexibility are subject to additional reporting and recordkeeping requirements. Specifically, the facility shall include a letter requesting this flexibility from the permitting authority. This initial request letter will detail the expected type, frequency, and duration of discharge. The letter will also include a certification that the facility has not considered the zero-discharge system optimization period in its availability timing request under § 423.11(t). After including flexibility for necessary discharges of the permeate or distillate in the permit, the permitting authority shall also extend any existing monitoring and reporting requirements to ensure that any necessary discharges of the distillate or permeate do not violate other applicable conditions of the permit such as water quality-based effluent limitations.

6. Requirement to Post Information to a Publicly Available Website

The reporting and recordkeeping requirements of the CCR rule included a novel approach for posting information to a publicly available website. This was done because, at the time the CCR rule was signed, the EPA did not have enforcement authority over the CCR rule. Thus, given the self-implementing nature of the regulations, EPA sought to make information more readily available to states, as well as members of the public, who could enforce the CCR rule through citizen suits.[226]

In contrast to the CCR rule, ELGs are implemented largely through authorized state permitting programs with EPA oversight. Nevertheless, one message that EPA received in initial outreach to communities was that there is a lack of trust of utilities (and in some cases, the states that regulate them). Another message was that there is an interest in more accessible information. At proposal, the EPA included a website posting requirement for all documentation included in § 423.19.

The EPA received comments both supporting and opposing the inclusion of a website requirement. Comments supporting the requirement desired additional transparency and suggested the EPA expand the requirement to all permitting documentation. Comments opposing the requirement expressed the opinion that these requirements would be a duplicative and unnecessary burden. One comment also pointed out that there was no provision for using a combined CCR rule/ELG rule website where a facility became subject to requirements after the effective date of the rule.

At the outset, the EPA agrees with commenters supporting a website reporting requirement. Given the success CCR rule websites have achieved in disseminating information to a variety of stakeholders, the EPA is finalizing a comparable posting requirement for the ELG rule. These websites will ensure transparency and ease of access to information. The EPA disagrees with these commenters that more is necessary. The existing reporting and recordkeeping requirements for general permitting provisions (*e.g.,* documentation during the permit application and permit modification processes, effluent reporting, etc.) are outside the scope of this rulemaking. Furthermore, even if the EPA were to consider broader changes to the reporting and recordkeeping requirements for all industrial categories, the Agency would do so through a rulemaking not specific to the steam electric power generating industry. Thus, the EPA is finalizing a website posting requirement only with respect to information contained in § 423.19.

Specifically, the EPA is requiring that all reporting and recordkeeping information not only be retained by the regulated entity and provided to the permitting authority, but that it also be posted to a public website for 10 years, or the length of the permit plus five years, whichever is longer. This posting requirement includes NOPPs and other filings that have occurred since the 2020 rule. The EPA is also allowing facilities to post on existing CCR rule compliance websites to reduce paperwork burden and make it easier for communities to access. One commenter correctly pointed out that, where facilities were not immediately subject to the reporting and recordkeeping requirements of § 423.19, it would have not been able to make the proper notification of combined CCR rule/ELG rule website usage within the proposed 60-day timeframe. Therefore, the EPA is finalizing a date for notification of this combined website that is July 8, 2024, or the date which the facility becomes subject to § 423.19 reporting requirements, whichever is later.

D. Site-Specific Water Quality-Based Effluent Limitations

The EPA regulations at 40 CFR 122.44(d)(1), implementing section 301(b)(1)(C) of the CWA, require each NPDES permit to include any requirements, in addition to or more stringent than ELGs or standards promulgated pursuant to sections 301, 304, 306, 307, 318, and 405 of the CWA, necessary to achieve water quality standards established under section 303 of the CWA, including state narrative criteria for water quality. Those same regulations require that limitations must control all pollutants or pollutant parameters (either conventional, nonconventional, or toxic pollutants) that the Director determines are or may be discharged at a level that will cause, have the reasonable potential to cause, or contribute to an excursion above any state water quality standard, including state narrative criteria for water quality. 40 CFR 122.44(d)(1)(i). In the sections below, the EPA describes the potential need to develop monitoring requirements and or limitations relating

[226] While the Water Infrastructure Improvements for the Nation Act later provided the EPA with permitting and oversight authority, the CCR rule continues to require posting to publicly available websites.

to bromide, per- and polyfluoroalkyl substances (PFAS), and Tribal rights.

1. Bromide

The preamble to the 2015 rule discussed bromide as a parameter for which water quality-based effluent limitations may be appropriate. The EPA stated its recommendation that permitting authorities carefully consider whether water quality-based effluent limitations for bromide or TDS would be appropriate for FGD wastewater discharged from steam electric power plants upstream of drinking water intakes. The EPA also stated its recommendation that the permitting authority notify any downstream drinking water treatment plants of the discharge of bromide.

The final rule requires zero discharge of FGD wastewater, BA transport water, and CRL. Nevertheless, the EPA is finalizing subcategories for these wastewaters that will allow some discharge of these wastewaters, and all three have been shown to have measurable levels of bromide.[227] Therefore, the records for the 2015 rule, the 2020 rule, and this action continue to suggest that permitting authorities should consider establishing water quality-based effluent limitations where necessary to meet applicable water quality standards to protect of populations served by downstream drinking water treatment plants.

In consultations conducted with state and local government entities, the EPA received comments from the American Water Works Association (AWWA) and the Association of Metropolitan Water Agencies. These comments requested that the EPA consider technologies that could treat upstream pollutants at the point of discharge, but also suggested that the EPA empower states to address the issue as well. The latter discussion referenced the approaches discussed in *Methods to Assess Anthropogenic Bromide Loads from Coal-Fired Power Plants and Their Potential Effect on Downstream Drinking Water Utilities.*[228] This document, provided in comments during the 2020 rulemaking and again during consultations on the current rulemaking, describes methodologies, data sources, and considerations for constructing an approach to bromide issues on a site-specific basis. This document presents additional data sources that NPDES permitting authorities could use to establish site-specific, water quality-based effluent limitations (*see, e.g.,* Figure 29 in AWWA's document). The document also provides examples of where states have already taken similar action. For example, AWWA cites California's 0.05 mg/L standard for in-river bromide to protect public health for specific waterways and drinking water treatment systems.

2. PFAS

In addition to considering water quality-based effluent limitations for parameters present in these wastestreams, the EPA also calls attention to the need to address potential for PFAS discharges. In the EPA's *PFAS Strategic Roadmap,*[229] the Agency laid out actions that would prevent PFAS from entering the environment. Specifically, the EPA stated it would ''proactively use existing NPDES authorities to reduce discharges of PFAS at the source and obtain more comprehensive information through monitoring on the sources of PFAS and quantity of PFAS discharged by these sources.'' The EPA's Office of Water issued a memorandum in 2022, covering facilities where the EPA is the permitting authority,[230] as well as guidance to state permitting authorities to address PFAS in NPDES permits.[231] While the steam electric power sector was not identified as one of the top PFAS dischargers, the EPA notes that PFAS may nevertheless be present in steam electric discharges. For example, the Wisconsin Department of Natural Resources has found PFAS at eight power plants.[232] In addition, firefighting foam used in exercises or actual fires at steam electric power plants could contain PFAS. Therefore, permitting or control authorities may appropriately consider whether PFAS monitoring and any further restrictions (*e.g.,* BMPs) would be appropriate at a given facility.

3. Tribal Reserved Rights

A third water-quality based consideration for steam electric power plants is Tribal reserved rights. Many Tribes hold reserved rights to resources on lands and waters where states establish water quality standards, through treaties, statutes, or other sources of Federal law. The U.S. Constitution defines treaties as the supreme law of the land. On December 5, 2022, the EPA proposed revisions to the Federal water quality standards (WQS) regulation at 40 CFR part 131. *See* 87 FR 74361 (Dec. 5, 2022) (''Tribal Reserved Rights proposed rule''). The proposed revisions, if finalized, would create a regulatory framework that would be applied case-specifically to protect aquatic and aquatic-dependent resources—such as fish—reserved to Tribes through treaties, statutes, and executive orders, in WOTUS. The Tribal Reserved Rights proposed rule aims to improve protection of resources reserved to Tribes and the health of Tribal members exercising their reserved rights, as well as transparency and predictability for Tribes, states, regulated community, and the public. The EPA is working to expeditiously finalize the proposed rule, taking into account public comments. During Tribal outreach on the Steam Electric ELG rulemaking, Tribes raised concerns about potential impacts to their Tribal reserved rights. For further discussion of EPA's outreach to Tribes, see section XV.F.

E. Severability

The purpose of this section is to clarify the Agency's intent with respect to the severability of provisions of this rule in the event of litigation. In the event of a stay or invalidation of any part of this rule, the Agency's intent is to preserve the remaining portions of the rule to the fullest possible extent. To dispel any doubt regarding the EPA's intent and to inform how the regulation would operate if severed, the EPA has added the following regulatory text at § 423.10(b): ''The provisions of this part are separate and severable from one another. If any provision is stayed or determined to be invalid, the remaining provisions shall continue in effect.'' This rule serves in many respects to further the goals of the CWA, and the Agency would have adopted each portion of this rule independent of the other portions. As explained below, the Agency carefully crafted this rule so that each provision or element of the rule

[227] The record also includes iodide in these discharges, another pollutant which should be considered alongside bromide for water quality-based effluent limitations.

[228] Available online at: *https://www.awwa.org/Portals/0/AWWA/ETS/Resources/17861ManagingBromideREPORT.pdf?ver=2020-01-09-151706-107.*

[229] U.S. EPA (Environmental Protection Agency). 2021. *PFAS Strategic Roadmap: EPA's Commitments to Action 2021–2024.* October 18. Available online at: *https://www.epa.gov/system/files/documents/2021-10/pfas-roadmap_final-508.pdf.*

[230] Fox, R. 2022. *Addressing PFAS Discharges in EPA-Issued NPDES Permits and Expectations Where EPA is the Pretreatment Control Authority.* April 28. Available online at: *https://www.epa.gov/system/files/documents/2022-04/npdes_pfas-memo.pdf.*

[231] Fox, R. 2022. *Addressing PFAS Discharges in NPDES Permits and Through the Pretreatment Program and Monitoring Programs.* December 5. Available online at: *https://www.epa.gov/system/files/documents/2022-12/NPDES_PFAS_State%20Memo_December_2022.pdf.*

[232] The maximum sampled concentrations in discharge from eight steam electric power plants were 28 ng/L for perfluorooctane sulfonic acid (PFOS) and 35 ng/L for perfluorooctanoic acid (PFOA), which the Wisconsin Department of Natural Resources theorized was due to concentration in cooling tower effluent.

can operate independently. Moreover, the Agency has organized the rule so that if any provision or element of this rule is determined by judicial review or operation of law to be invalid, that partial invalidation will not render the remainder of this rule invalid.

This rule primarily regulates discharges associated with four steam electric wastestreams. The rule provides limitations and standards associated with each wastestream in separate sections that do not rely on one another. The decision to regulate each wastestream was made independently of the decisions to regulate the other wastestreams. This is because the EPA applied the BAT statutory factors in its decision for each wastestream. This is consistent with the Fifth Circuit's decision in *Southwestern Elec. Power Co.* v. *EPA,* in which the Court held that the EPA must apply the BAT factors with respect to each wastestream, in that case CRL. *Southwestern Elec. Power Co.* v. *EPA,* 920 F.3d at 1027. Indeed, the Court ultimately vacated only those portions of the 2015 rule regulating legacy wastewater and CRL, without disturbing any further aspects of the rule. *Id.* at 1033.

This rule also contains several subcategories. The rule provides limitations and standards associated with each subcategory in separate sections, which are not relied on by other aspects of the rule. The decision to subcategorize particular discharges, for example, certain discharges of unmanaged CRL or certain discharges of legacy wastewater, had no bearing on the BAT decisions made with respect to the rest of the industry, for which the EPA finds the rule is technologically available and economically achievable after a consideration of the CWA section 304(b) factors. And each subcategory is supported by its own, independent BAT determination. Moreover, the rest of the industry's requirements are not tied in the regulatory text to the requirements of the subcategories. Similarly, the decision to subcategorize certain discharges from EGUs expected to cease combustion of coal had no bearing on the EPA's BAT decisions made with respect to the rest of the industry, for which the EPA finds the rule is technologically available and economically achievable after a consideration of the CWA section 304(b) factors. And the cease combustion of coal subcategories are supported by their own, independent BAT determinations. Moreover, the rest of the industry's requirements are not tied in the regulatory text to the requirements of the subcategories. Were the EPA to receive an adverse decision on any of the subcategories established in this rule, the EPA would expect to potentially address any remand and/or vacatur of the limitations applicable to the subcategory by considering the Court's opinion and the requisite statutory factors in re-promulgating any appropriate limitations for such subcategory. The EPA would, for example, have to demonstrate that any new limitations for the subcategory are technologically available and economically achievable for the subcategory, after a consideration of the CWA section 304(b) factors. These examples are illustrative, rather than exhaustive, and the EPA intends each portion of the rule to be independent and severable. Furthermore, if the application of any portion of this rule to a particular circumstance is determined to be invalid, the Agency intends that the rule remain applicable to all other circumstances.

XV. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action is a ''significant regulatory action,'' as defined under section 3(f)(1) of Executive Order 12866, as amended by Executive Order 14094. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. The EPA has included redline strikeout versions showing changes made in response to the Executive Order 12866 review available in the docket. The EPA prepared an analysis of the estimated costs and benefits associated with this action. This analysis is contained in section 12 of the BCA and is also available in the docket.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2752.02 and OMB Control Number 2040–0310. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

As described in section XIV.C, the EPA is finalizing several changes to the individual reporting and recordkeeping requirements of § 423.19 for specific subcategories of plants and/or plants that have certain types of discharges. The EPA is adding reporting and recordkeeping requirements for plants in the permanent cessation of coal combustion by 2034 subcategory and for plants that discharge unmanaged CRL. EPA is also removing reporting and recordkeeping requirements for LUEGUs and finalizing a new requirement for plants to post reports to a publicly available website.

Respondents/affected entities: The respondents affected by this ICR are steam electric power plants. The North American Industry Classification System (NAICS) identification number applicable to respondents is 221112: Electric Power Generation Plants—Fossil Fuel Electric Power Generation. The U.S. Census Bureau describes this U.S. industry as establishments primarily engaged in operating fossil-fuel-powered electric power generation facilities. These facilities use fossil fuels, such as coal, oil, or gas, in an internal combustion or a combustion turbine conventional steam process to produce electric energy. The electric energy produced in these establishments is provided to electric power transmission systems or to electric power distribution systems.

Respondent's obligation to respond: Mandatory (40 CFR parts 423 and 122).

Estimated number of respondents: The EPA estimates that 236 steam electric facilities would be subject to this final rule.

Frequency of response: The EPA made the following assumptions for estimating frequency:

- NOPPs, notices, and the Combustion Residual Leachate Monitoring Report (CRLMR) would be submitted one time (in the first year of the requirements).
- Progress reports and the annual CRLMR would be submitted once a year following the submittal of the official NOPP (*i.e.,* twice over a three-year period).
- Progress reports associated with EPA's VIP program or NOPPs that have already been submitted would be submitted once a year following the publication of the final rule.

Total estimated burden: For facilities, the estimated facility universe for any reporting, for the purpose of this estimate is 236 facilities. The EPA estimates the total one-time labor hours associated with this ICR to facilities is 6,520 and total annual labor hours of 22,000 hours for a total annual average of 24,300 hours. Similarly, the EPA estimates the total one-time labor costs

to facilities to be $650,000 and total annual labor costs of about $2,300,000 for a total annual average of $2,540,000. For permitting/control authorities, the estimated universe is 41. The EPA estimates the total one-time labor hours associated with this ICR to permitting/control authorities is 416 and total annual labor hours ranging from 3,050 to 3,160 for a total annual average of 3,230 hours. Similarly, the EPA estimates the total one-time labor costs to permitting/control authorities to be $33,300 and total annual labor costs range from $256,000 to $265,000 for a total annual average of $273,000.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action include small businesses and small governmental jurisdictions that own steam electric plants. The EPA has determined that 220 to 391 entities own steam electric power plants subject to the ELGs, of which 117 to 202 entities are small. These small entities own a total of 267 steam electric power plants (out of the total of 858 plants), including 33 to 39 plants estimated to incur costs under the final rule under the lower and upper cost scenarios, respectively. The EPA considered the impacts of the final rule on small businesses using a cost-to-revenue test. The analysis compares the cost of implementing wastewater controls under the final rule to those under baseline (which reflects the 2020 rule, as explained in section V of this preamble). Small entities estimated to incur compliance costs exceeding one or more of the one percent and three percent impact thresholds were identified as potentially incurring a significant impact. For the final rule under the lower bound cost scenario, the EPA's analysis shows 10 small entities (4 non-utilities, 3 cooperatives, and 3 municipalities) expected to incur incremental costs equal to or greater than one percent of revenue. For 5 of these small entities (2 non-utilities, 2 cooperatives, and 1 municipality), the incremental cost of the final rule exceeds three percent of revenue. For the upper bound cost scenario, an additional 2 small entities (both non-utilities) have costs equal to or greater than one percent of revenue for a total of 12 entities. For 2 non-utilities, 3 cooperatives, and 2 municipalities, these costs exceed three percent of revenue. Details of this analysis are presented in section 8 of the RIA, included in the docket.

These results support the EPA's finding of no significant impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action contains a Federal mandate under the UMRA, 2 U.S.C. 1531–1538 that may result in expenditures of $100 million (adjusted annually for inflation) or more for state, local, and Tribal governments, in the aggregate, or the private sector in any one year ($198 million in 2023 dollars). Accordingly, the EPA has prepared a written statement required under section 202 of UMRA. The statement is included in the docket for this action (see section 9 in the RIA) and briefly summarized below.

Consistent with the intergovernmental consultation provisions of section 204 of the UMRA, the EPA consulted with government entities potentially affected by this rule. The EPA described the government-to-government dialogue leading to the proposed rule in its preamble to the proposed rulemaking. The EPA received comments from state and local government representatives in response to the proposed rule and considered this input in developing the final rule.

Consistent with section 205, the EPA has identified and considered a reasonable number of regulatory alternatives to develop BAT. The main regulatory options are described in section VII of this preamble. These options included a range of technology-based approaches. As discussed in detail in section VII.B of this preamble, the EPA is selecting Option B as the BAT after considering the factors required under CWA section 304(b)(2)(B). The technologies are available, are economically achievable, and have acceptable non-water quality environmental impacts.

This final rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. To assess the impact of compliance requirements on small governments (*i.e.,* governments with a population of less than 50,000), the EPA compared total costs and costs per plant estimated to be incurred by small governments with the costs estimated to be incurred by large governments. The EPA also compared costs for small government-owned plants with those of non-government-owned facilities. The Agency evaluated both the average and maximum annualized costs per plant under both the lower and upper bound cost scenarios. section 9 of the RIA provides details of these analyses. In all these comparisons, both for the cost totals and, in particular, for the average and maximum cost per plant, the costs for small government-owned facilities were less than those for small non-government-owned facilities. This was true for both the lower and upper bound cost scenarios. The maximum cost per plant was also smaller for the small government-owned plants vs. the large government-owned plants under the lower bound cost scenario. The average annualized costs per plant were larger for small government-owned plants vs. large government-owned plants under the upper bound cost scenario, but not markedly so. On this basis, the EPA concludes that the compliance cost requirements of the steam electric ELGs would not significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

The EPA has concluded that this action has federalism implications because it imposes direct compliance costs on state or local governments, and the Federal Government will not provide the funds necessary to pay those costs.

As discussed in section XV.B, the EPA anticipates that this final rule does not impose incremental administrative burden on states from issuing, reviewing, and overseeing compliance with discharge requirements. The EPA has identified 148 steam electric power plants owned by 63 state or local government entities. Under the final rule, the EPA projects that 15 government-owned plants would incur compliance costs. The EPA estimates the maximum compliance cost in any one year to governments (excluding the Federal Government) for the final rule range from $155 million and $220 million, whereas the annualized costs range between $40 million and $67 million (see section 9 of the RIA for details).

The EPA provides the following federalism summary impact statement.

The EPA consulted with state and local officials early in the process of developing the rule to permit them to

have meaningful and timely input into its development. The preamble to the proposed rule described these consultations, which included a meeting held on January 27, 2022, attended by representatives from 15 state and local government organizations and outreach with several intergovernmental associations representing elected officials and encouraged their members to participate in the meeting, including the National Governors Association, the National Conference of State Legislatures, the Council of State Governments, the National Association of Counties, the National League of Cities, the U.S. Conference of Mayors, the County Executives of America, and the National Associations of Towns and Townships.

The EPA received five sets of unique written comments after the meeting and considered these comments in the development of the proposed rule. For further information regarding the consultation process and supplemental materials provided to state and local government representatives, please go to the steam electric power generating effluent guidelines website at: *https://www.epa.gov/eg/2021-supplemental-steam-electric-rulemaking.*

The EPA received comment on the proposed ELGs from three state and local officials or their representatives. Some state and local officials expressed concerns the EPA had underestimated the costs and overstated the pollutant removals of the technology options. Commenters stated that the ELGs would impose significant costs on small entities and would result in electricity rate increases that are unaffordable for households. Commenters also expressed concern about coordination of the various rules affecting the power sector. The EPA considered these comments in developing the final rule.

A list of the state and local government commenters has been provided to OMB and has been placed in the docket for this rulemaking. In addition, the detailed response to comments from these entities is contained in the EPA's response to comments document on this final rulemaking, which has also been placed in the docket for this rulemaking.

As explained in section VII of this preamble, the EPA is establishing more stringent limitations on several wastestreams that would alleviate concerns raised by the public water systems. At the same time, the EPA's final rule includes subcategories for units certifying to the permanent cessation of coal combustion. The EPA believes these differentiated requirements alleviate some of the concerns raised by publicly owned utilities. Further, as explained in section VIII of this preamble, the EPA's analysis demonstrates that the final requirements are economically achievable for the steam electric power generating industry as a whole and for plants owned by state or local government entities.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has Tribal implications; however, it will neither impose substantial direct compliance costs on federally recognized Tribal governments, nor preempt Tribal law, as specified in Executive Order 13175. *See* 65 FR 67249 (November 9, 2000). It does not have substantial direct effects on Tribal governments, on the relationship between the Federal Government and the Indian Tribes, or the distribution of power and responsibilities between the Federal Government and Indian Tribes as specified in Executive Order 13175. The EPA's analyses show that no facility subject to the final ELGs is owned by Tribal governments. Thus, Executive Order 13175 does not apply to this action. The EPA acknowledges this action has Tribal implications, not prescribed in Executive Order 13175, because during Tribal Consultation, the EPA received written comments from 3 Tribal nations that conveyed the importance of historical Tribal waters and rights (*e.g.,* fishing, trapping), recommended more stringent technological controls to protect those rights, or encouraged retirement or fuel conversion of old coal-fired EGUs.

Although Executive Order 13175 does not apply to this action, the EPA consulted with Tribal officials early in the process of developing this rule to enable them to have meaningful and timely input into its development. The EPA initiated consultation and coordination with federally recognized Tribal governments in January 2022, sharing information about the steam electric effluent guidelines rulemaking with the National Tribal Caucus, the National Tribal Water Council, and several individual Tribes. The EPA continued this government-to-government dialogue and, on February 1 and February 9, 2022, invited Tribal representatives to participate in further discussions about the rulemaking process and objectives, with a focus on identifying specific ways the rulemaking may affect Tribes.[233] The consultation process ended on March 29, 2022. The EPA is including in the docket for this action a memorandum that provides a response to the comments it received through this consultation and the consultations described in sections XVI.D and XVI.E of this preamble. For further information regarding the consultation process and supplemental materials provided to Tribal representatives, please go to the steam electric power generating effluent guidelines website at: *https://www.epa.gov/eg/2021-supplemental-steam-electric-rulemaking.*

Representatives from several Tribes provided input to the rule. The EPA considered input from Tribal representatives in developing this final rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This action's health and risk assessments are discussed in sections 4 and 5 of the BCA and are summarized below.

The EPA identified several ways in which the final rule will benefit children, including by potentially reducing health risks from exposure to pollutants present in steam electric power plant discharges, or through impacts of the discharges on the quality of source water used by public water systems. This reduction arises from more stringent pollutant limitations as compared to baseline. The EPA quantified the changes in IQ losses from lead exposure among preschool children and from mercury exposure *in utero* resulting from maternal fish consumption under the final rule as compared to baseline. The EPA also estimated changes in the lifetime risk of developing bladder cancer due to exposure to TTHM in drinking water, or of cardiovascular premature mortality from exposure to lead. For these analyses, the EPA did not estimate children-specific risks because these adverse health effects normally follow

[233] As discussed in sections XIII and XVI.J, the EPA also did targeted outreach to communities in the top tier of its EJ screening analysis which included two tribal communities.

long-term exposure. Finally, the EPA estimated changes in air-related adverse health effects resulting from changes in the profile of electricity generation under the final rule as compared to baseline. The analysis found that the resulting reductions in $PM_{2.5}$ and ozone will benefit children by reducing asthma onset and symptoms, allergy symptoms, emergency room visits and hospital visits for respiratory conditions, and school absences.

However, the EPA's Policy on Children's Health applies to this action. Information on how the Policy was applied is available under ''Children's Environmental Health'' in this **SUPPLEMENTARY INFORMATION** section.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This final action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The EPA analyzed the potential energy effects of the final rule relative to baseline and found minimal or no impacts on electricity generation, generating capacity, cost of energy production, or dependence on a foreign supply of energy. Specifically, the Agency's analysis found that the final rule would not reduce electricity production by more than 1 billion kWhs per year or by 500 MW of installed capacity, nor would the final rule increase U.S. dependence on foreign energy supplies. For more detail on the potential energy effects of this action, see section 10.7 in the RIA, available in the docket.

I. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations and Executive Order 14096: Revitalizing Our Nation's Commitment to Environmental Justice for All

The EPA believes that the human health or environmental conditions existing prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on communities with EJ concerns. Current research suggests that coal-fired power plants tend to be in low-income communities, Indigenous communities, and communities of color. Toomey (2013) reported that 78 percent of African Americans in the United States live within a 30-mile radius of a coal-fired power plant.[234] Impacts discussed in the reports included adverse health impacts resulting from air pollutants (*e.g.,* SO_2, NO_X, $PM_{2.5}$) for those living in proximity to coal-fired power plants, climate justice issues resulting from GHG emissions, and risk of impoundment failures for populations living in proximity to coal waste surface impoundments where coal is mined.[235] [236] [237] All these impacts were found in one or more papers to disproportionately impact low-income, minority, and Indigenous communities. The EPA also conducted a proximity analysis to characterize the demographics of communities potentially exposed to pollution from steam electric power plant wastewater discharges through proximity to plants, proximity to downstream surface waters receiving, or being served by a PWS using impacted downstream receiving waters as source water for drinking water. The results of the EPA's analysis showed that these communities have higher proportions of low-income individuals and people of color compared to the national average, national rural average, and respective state averages suggesting potential EJ concerns under the baseline in terms of disproportionate exposures. The EPA believes that this action is likely to reduce existing disproportionate and adverse effects on communities with EJ concerns. The EPA's EJ analysis showed the final rule will reduce differential baseline exposures for low-income communities and communities of color to pollutants in wastewater and resulting human impacts. Improvements to water quality, wildlife, and human health resulting from reductions in pollutants in surface water will be distributed more among communities with EJ concerns under some or all of the regulatory options due to their disproportionate exposures under the baseline. Drinking water improvements will also be distributed more among communities with EJ concerns under the final rule due to their disproportionate exposures under the baseline. Remaining exposures, impacts, and benefits analyzed are small enough that EPA could not conclude whether changes in disproportionate impacts under the baseline would occur. While the changes in GHGs attributable to the final rule are small compared to worldwide emissions, findings from peer-reviewed evaluations demonstrate that actions that reduce GHG emissions are also likely to reduce climate-related impacts on vulnerable communities, including communities with EJ concerns. Costs of the final rule in terms of electricity price increases among residential households may impact low-income households and households of color more relative to all households as low-income households and households of color tend to spend a greater proportion of their income on energy expenditures. Despite this, the potential price increases under the upper bound cost scenario represent between less than 0.1 percent and 0.2 percent of energy expenditures for all income, race groups, and income quintiles, and therefore the EPA does not expect costs to have a substantial impact on low-income households and households of color.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

Appendix A to the Preamble: Definitions, Acronyms, and Abbreviations Used in This Preamble

The following acronyms, abbreviations, and terms are used in this preamble. These terms are provided the reader's for convenience; they are not regulatory definitions with the force or effect of law, nor are they to be used as guidance for implementation of this rule.

Administrator. The Administrator of the U.S. Environmental Protection Agency.

Agency. U.S. Environmental Protection Agency.

BAT. Best available technology economically achievable, as defined by CWA sections 301(b)(2)(A) and 304(b)(2)(B).

BA transport water. Wastewater that is used to convey bottom ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash.

BCA. Abbreviation used for the *Benefit and Cost Analysis for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report.

[234] Toomey, D. 2013. *Coal Pollution and the Fight for Environmental Justice.* Yale Environment 360. June 19. Available online at: *https://www.e360.yale.edu/features/naacp_jacqueline_patterson_coal_pollution_and_fight_for_environmental_justice.*

[235] Liévanos, R., Greenberg, P., Wishart, P. 2018. *In the Shadow of Production: Coal Waste Accumulation and Environmental Inequality Formation in Eastern Kentucky,* pp. 37–55.

[236] Israel, B. 2012. *Coal Plants Smother Communities of Color. https://www.scientificamerican.com/article/coal-plants-smother-communities-of-color/#:~:text=People%20living%20near%20coal%20plants,percent%20are%20people%20of%20color.*

[237] NAACP (National Association for the Advancement of Colored People). 2012. *Coal Blooded: Putting Profits Before People. www.naacp.org/resources/coal-blooded-putting-profits-people.*

Bioaccumulation. A general term describing a process by which chemicals are taken up by an organism either directly from exposure to a contaminated medium or by consumption of food containing the chemicals, resulting in a net accumulation of the chemical over time by the organism.

BMP. Best management practice.

BA. Bottom ash. The ash, including EGU slag, that settles in a furnace or is dislodged from furnace walls. Economizer ash is included when it is collected with BA.

BA purge water. The water discharged from a wet BA handling system that recycles some, but not all, of its BA transport water.

BPT. The best practicable control technology currently available, as defined by CWA sections 301(b)(1) and 304(b)(1).

CBI. Confidential business information.

CCR. Coal combustion residuals.

CWA. Clean Water Act; the Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 *et seq.*), as amended, *e.g.,* by the Clean Water Act of 1977 (Pub. L. 95–217) and the Water Quality Act of 1987 (Pub. L. 100–4).

Combustion residuals. Solid wastes associated with combustion-related steam electric power plant processes, including fly ash and BA from coal-, petroleum coke-, or oil-fired units; FGD solids; FGMC wastes; and other wastewater treatment solids associated with steam electric power plant wastewater. In addition to the residuals associated with coal combustion, this also includes residuals associated with the combustion of other fossil fuels.

CRL. Combustion residual leachate. Leachate from landfills or surface impoundments that contains combustion residuals. Leachate is composed of liquid, including any suspended or dissolved constituents in the liquid, that has percolated through waste or other materials emplaced in a landfill, or that passes through the surface impoundment's containment structure (*e.g.,* bottom, dikes, berms). Combustion residual leachate includes seepage and/or leakage from a combustion residual landfill or impoundment unit. It also includes wastewater from landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility.

CWA. Clean Water Act.

Direct discharge. (1) Any addition of any ''pollutant'' or combination of pollutants to ''waters of the United States'' from any ''point source'' or (2) any addition of any pollutant or combination of pollutant to waters of the ''contiguous zone'' or the ocean from any point source other than a vessel or other floating craft that is being used as a means of transportation. This definition includes additions of pollutants into waters of the United States from surface runoff that is collected or channeled by man; discharges through pipes, sewers, or other conveyances owned by a state, municipality, or other person that do not lead to a treatment works; and discharges through pipes, sewers, or other conveyances that lead into privately owned treatment works. This term does not include addition of pollutants by any ''indirect discharger.''

Direct discharger. A plant that discharges treated or untreated wastewaters into waters of the United States.

DOE. Department of Energy.

Dry BA handling system. A system that does not use water as the transport medium to convey BA away from the EGU. Dry-handling systems include systems that collect and convey the BA without using any water, as well as systems in which BA is quenched in a water bath and then mechanically or pneumatically conveyed away from the EGU. Dry BA handling systems do not include wet sluicing systems (such as remote MDS or complete recycle systems).

Effluent limitation. Under CWA section 502(11), any restriction, including schedules of compliance, established by a state or the Administrator on quantities, rates, and concentrations of chemical, physical, biological, and other constituents that are discharged from point sources into navigable waters, the waters of the contiguous zone, or the ocean.

EGU. Electric generating unit.

EIA. Energy Information Administration.

EJA. Abbreviation used for the *Environmental Justice Analysis for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report.

ELGs. Effluent limitations guidelines and standards.

E.O. Executive order.

EPA. U.S. Environmental Protection Agency.

FA. Fly ash. The ash that is carried out of the furnace by a gas stream and collected by a capture device such as a mechanical precipitator, electrostatic precipitator, and/or fabric filter. Economizer ash is included in this definition when it is collected with FA. Ash is not included in this definition when it is collected in wet scrubber air pollution control systems whose primary purpose is particulate removal.

Facility. Any NPDES ''point source'' or any other facility or activity (including land or appurtenances thereto) that is subject to regulation under the NPDES program.

FA transport water. Wastewater that is used to convey fly ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash.

FGD. Flue gas desulfurization.

FGMC. Flue gas mercury control.

FGD wastewater. Wastewater generated specifically from the wet FGD scrubber system that contacts the flue gas or the FGD solids, including, but not limited to, the blowdown or purge from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater.

FGMC wastewater. Any wastewater generated from an air pollution control system installed or operated for the purpose of removing mercury from flue gas. This includes wastewater from fly ash collection systems when the particulate control system follows sorbent injection or other controls to remove mercury from flue gas. FGD wastewater generated at plants using oxidizing agents to remove mercury in the FGD system and not in a separate FGMC system is not considered FGMC wastewater.

Gasification wastewater. Any wastewater generated at an integrated gasification combined cycle operation from the gasifier or the syngas cleaning, combustion, and cooling processes. Gasification wastewater includes, but is not limited to, the following: sour/grey water; CO_2/steam stripper wastewater; sulfur recovery unit blowdown; and wastewater resulting from slag handling or fly ash handling, particulate removal, halogen removal, or trace organic removal. Air separation unit blowdown, noncontact cooling water, and runoff from fuel and/or byproduct piles are not considered gasification wastewater. Wastewater that is collected intermittently in floor drains in the gasification process area from leaks, spills, and cleaning occurring during normal operation of the gasification operation is not considered gasification wastewater.

Groundwater. Water that is found in the saturated part of the ground underneath the land surface.

Indirect discharge. Wastewater discharged or otherwise introduced to a POTW.

IPM. Integrated Planning Model.

Landfill. A disposal facility or part of a facility or plant where solid waste, sludges, or other process residuals are placed in or on any natural or manmade formation in the earth for disposal and which is not a storage pile, a land treatment facility, a surface impoundment, an underground injection well, a salt dome or salt bed formation, an underground mine, a cave, or a corrective action management unit.

Legacy wastewater. FGD wastewater, BA transport water, FA transport water, CRL, gasification wastewater and/or FGMC wastewater generated before the ''as soon as possible'' date that more stringent effluent limitations from the 2015 or 2020 rules would apply.

MDS. Mechanical drag system.BA handling system that collects BA from the bottom of an EGU in a water-filled trough. The water bath in the trough quenches the hot BA as it falls from the EGU and seals the EGU gases. A drag chain operates in a continuous loop to drag BA from the water trough up an incline, which dewaters the BA by gravity, draining the water back to the trough as the BA moves upward. The dewatered BA is often conveyed to a nearby collection area, such as a small bunker outside the EGU building, from which it is loaded onto trucks and either sold or transported to a landfill. The MDS is considered a dry BA handling system because the ash transport mechanism is mechanical removal by the drag chain, not the water.

Mortality. Death rate or proportion of deaths in a population.

NAICS. North American Industry Classification System.

NPDES. National Pollutant Discharge Elimination System.

NSPS. New Source Performance Standards.

ORP. Oxidation-reduction potential.

Paste. A substance containing solids in a fluid which behaves as a solid until a force is applied that causes it to behave like a fluid.

Paste landfill. A landfill that receives any paste designed to set into a solid after the passage of a reasonable amount of time.

Point source. Any discernible, confined, and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, vessel, or other floating craft from which pollutants are or may be discharged. The term does not include agricultural stormwater discharges or return flows from irrigated agriculture. *See* CWA section 502(14), 33 U.S.C. 1362(14); 40 CFR 122.2.

POTW. Publicly owned treatment works. *See* CWA section 212, 33 U.S.C. 1292; 40 CFR 122.2, 403.3.

PSES. Pretreatment Standards for Existing Sources.

PSC. Public service commission.

PUC. Public utility commission.

RCRA. The Resource Conservation and Recovery Act of 1976, 42 U.S.C. 6901 *et seq.*

Remote MDS. BA handling system that collects BA at the bottom of the EGU, then uses transport water to sluice the ash to a remote MDS that dewaters BA using a configuration similar to MDS. The remote MDS is considered a wet BA handling system because the ash transport mechanism is water.

RO. Reverse osmosis.

RFA. Regulatory Flexibility Act.

SBA. Small Business Administration.

Sediment. Particulate matter lying below water.

Surface water. All waters of the United States, including rivers, streams, lakes, reservoirs, and seas.

TDD. Abbreviation used for the *Technical Development Document for the Final Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* report.

Toxic pollutants. As identified under the CWA, 65 pollutants and classes of pollutants, of which 126 specific substances have been designated priority toxic pollutants. *See* appendix A to 40 CFR part 423.

Transport water. Wastewater that is used to convey FA, BA, or economizer ash from the ash collection or storage equipment or EGU and that has direct contact with the ash. Transport water does not include low-volume, short-duration discharges of wastewater from minor leaks (*e.g.,* leaks from valve packing, pipe flanges, or piping) or minor maintenance events (*e.g.,* replacement of valves or pipe sections).

UMRA. Unfunded Mandates Reform Act.

Wet BA handling system. A system in which BA is conveyed away from the EGU using water as a transport medium. Wet BA systems typically send the ash slurry to dewatering bins or a surface impoundment. Wet BA handling systems include systems that operate in conjunction with a traditional wet sluicing system to recycle all BA transport water (*e.g.,* remote MDS or complete recycle systems).

Wet FGD system. Wet FGD systems capture sulfur dioxide from the flue gas using a sorbent that has mixed with water to form a wet slurry, and that generates a water stream that exits the FGD scrubber absorber.

List of Subjects in 40 CFR Part 423

Environmental protection, Electric power generation, Power facilities, Waste treatment and disposal, Water pollution control.

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency amends 40 CFR part 423 as follows:

PART 423—STEAM ELECTRIC POWER GENERATING POINT SOURCE CATEGORY

■ 1. The authority citation for part 423 is revised to read as follows:

Authority: 33 U.S.C. 1251 *et seq.;* 1311; 1314(b), (c), (e), (g), and (i)(A) and (B); 1316; 1317; 1318 and 1361.

■ 2. Revise § 423.10 to read as follows:

§ 423.10 Applicability and severability.

(a) *Applicability.* The provisions of this part apply to discharges resulting from the operation of a generating unit by an establishment whose generation of electricity is the predominant source of revenue or principal reason for operation, and whose generation of electricity results primarily from a process utilizing fossil-type fuel (coal, oil, or gas), fuel derived from fossil fuel (*e.g.,* petroleum coke, synthesis gas), or nuclear fuel in conjunction with a thermal cycle employing the steam water system as the thermodynamic medium. This part applies to discharges associated with both the combustion turbine and steam turbine portions of a combined cycle generating unit.

(b) *Severability.* The provisions of this part are separate and severable from one another. If any provision is stayed or determined to be invalid, the remaining provisions shall continue in effect.

■ 3. Amend § 423.11 by revising paragraphs (n), (p), (r), (w), (z), and (bb) and adding paragraphs (ee) and (ff) to read as follows:

§ 423.11 Specialized definitions.

* * * * *

(n) The term *flue gas desulfurization (FGD) wastewater* means any wastewater generated specifically from the wet flue gas desulfurization scrubber system that comes into contact with the flue gas or the FGD solids, including but not limited to, the blowdown from the FGD scrubber system, overflow or underflow from the solids separation process, FGD solids wash water, and the filtrate from the solids dewatering process. Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment; FGD paste equipment cleaning water; treated FGD wastewater permeate or distillate used as boiler makeup water; water that is collected in floor drains in the FGD process area; wastewater removed from FGD wastewater treatment equipment within the first 120 days of decommissioning the equipment, or wastewater generated by a 10-year, 24-hour or longer duration storm event when meeting the certification requirements in § 423.19(o) is not considered FGD wastewater.

* * * * *

(p) The term *transport water* means any wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (*e.g.,* leaks from valve packing, pipe flanges, or piping), minor maintenance events (*e.g.,* replacement of valves or pipe sections), FGD paste equipment cleaning water, bottom ash purge water, wastewater removed from ash handling equipment within the first 120 days of decommissioning the equipment, or wastewater generated by a 10-year, 24-hour or longer duration storm event when meeting the certification requirements in § 423.19(o).

* * * * *

(r) The term *combustion residual leachate* means leachate from landfills or surface impoundments containing combustion residuals. Leachate is composed of liquid, including any suspended or dissolved constituents in the liquid, that has percolated through waste or other materials emplaced in a landfill, or that passes through the surface impoundment's containment structure (*e.g.,* bottom, dikes, berms). Combustion residual leachate includes seepage and/or leakage from a combustion residual landfill or impoundment unit. Combustion residual leachate includes wastewater from landfills and surface impoundments located on non-adjoining property when under the operational control of the permitted facility. Combustion residual leachate does not include wastewater generated by a 10-year, 24-hour or longer duration storm event when meeting the certification requirements in § 423.19(o).

* * * * *

(w) The term *permanent cessation of coal combustion* means the owner or operator certifies under § 423.19(g) or (h) that an electric generating unit will cease combustion of coal no later than December 31, 2028, or December 31, 2034.

* * * * *

(z) The term *low utilization electric generating unit* means any electric generating unit for which the facility owner certifies, and annually recertifies, under § 423.19(f) that the two-year average annual capacity utilization rating is less than 10 percent.

* * * * *

(bb) The term *tank* means a stationary device, designed to contain an accumulation of wastewater which is constructed primarily of non-earthen materials (*e.g.,* wood, concrete, steel, plastic) which provide structural support and which is not a coal combustion residual surface impoundment.

* * * * *

(ee) The term *coal combustion residual surface impoundment* means a natural topographic depression, man-made excavation, or diked area, which is designed to hold an accumulation of coal combustion residuals and liquids, and the unit treats, stores, or disposes of coal combustion residuals.

(ff) The term *unmanaged combustion residual leachate* means combustion residual leachate which either:

(1) Is determined by the permitting authority to be the functional equivalent of a direct discharge to waters of the United States (WOTUS) through groundwater; or

(2) Has leached from a waste management unit into the subsurface and mixed with groundwater prior to being captured and pumped to the surface for discharge directly to WOTUS.

■ 4. Amend § 423.13 by:

■ a. Revising paragraph (g);

■ b. Adding a heading for paragraph (h);

■ c. Revising paragraph (h)(1)(ii);

■ d. Adding a heading for paragraph (i);

■ e. Revising paragraph (i)(1)(ii); and

■ f. Revising paragraphs (k), (l), and (o).

The revisions and additions read as follows:

§ 423.13 Effluent limitations guidelines representing the degree of effluent reduction attainable by the application of the best available technology economically achievable (BAT).

* * * * *

(g) *FGD wastewater*—(1) *2020 BAT.* (i) Except for those discharges to which paragraph (g)(2) or (3) of this section applies, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in table 5 to this paragraph (g)(1)(i). Dischargers must meet the effluent limitations for FGD wastewater in this paragraph (g)(1)(i) by a date determined by the permitting authority that is as soon as possible beginning October 13, 2021, but no later than December 31, 2025. The effluent limitations in this paragraph (g)(1)(i) apply to the discharge of FGD wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph (g)(1)(i), until the date determined by the permitting authority for meeting the effluent limitations in paragraph (g)(4) of this section.

TABLE 5 TO PARAGRAPH (g)(1)(i)

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	18	8
Mercury, total (ng/L)	103	34
Selenium, total (μg/L)	70	29
Nitrate/nitrite as N (mg/L)	4	3

(ii) For FGD wastewater generated before the date determined by the permitting authority, as specified in paragraph (g)(1)(i) of this section, the EPA is declining to establish BAT limitations and is reserving such limitations to be established by the permitting authority on a case-by-case basis using the permitting authority's best professional judgment.

(2) *2020 BAT subcategories.* (i) For any electric generating unit with a total nameplate capacity of less than or equal to 50 megawatts, that is an oil-fired unit, or for which the owner has submitted a certification pursuant to § 423.19(g), the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed for total suspended solids (TSS) in § 423.12(b)(11).

(A) For any electric generating unit for which the owner has submitted a certification pursuant to § 423.19(g), where such unit has permanently ceased coal combustion by December 31, 2028, there shall be no discharge of pollutants in FGD wastewater after April 30, 2029.

(B) For any electric generating unit for which the owner has submitted a certification pursuant to § 423.19(g), where such unit has failed to permanently cease coal combustion by December 31, 2028, there shall be no discharge of pollutants in FGD wastewater after December 31, 2028.

(ii) For FGD wastewater discharges from a high FGD flow facility, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in table 6 to this paragraph (g)(2)(ii). Dischargers must meet the effluent limitations for FGD wastewater in this paragraph (g)(2)(ii) by a date determined by the permitting authority that is as soon as possible beginning October 13, 2021, but no later than December 31, 2023. The effluent limitations in this paragraph (g)(2)(ii) apply to the discharge of FGD wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph (g)(2)(ii), until the date determined by the permitting authority for meeting the effluent limitations in paragraph (g)(4) of this section.

TABLE 6 TO PARAGRAPH (g)(2)(ii)

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

(iii) For FGD wastewater discharges from a low utilization electric generating unit, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in table 6 to paragraph (g)(2)(ii) of this section. Dischargers must meet the effluent limitations for FGD wastewater in this paragraph (g)(2)(iii) by a date determined by the permitting authority that is as soon as possible beginning October 13, 2021, but no later than December 31, 2023. These effluent limitations apply to the discharge of FGD wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph (g)(2)(iii), until the date determined by the permitting authority for meeting the effluent limitations in paragraph (g)(4) of this section.

(3) *Voluntary incentives plan.* (i) For dischargers who voluntarily choose to meet the effluent limitations for FGD wastewater in this paragraph (g)(3)(i), the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in table 7 to this paragraph (g)(3)(i). Dischargers who choose to meet the effluent limitations for FGD wastewater in this paragraph (g)(3)(i) must meet such limitations by December 31, 2028. The effluent limitations in this paragraph (g)(3)(i) apply to the discharge of FGD wastewater generated on and after December 31, 2028.

TABLE 7 TO PARAGRAPH (g)(3)(i)

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (ug/L)	5	NA
Mercury, total (ng/L)	23	10
Selenium, total (ug/L)	10	NA
Nitrate/Nitrite (mg/L)	2.0	1.2
Bromide (mg/L)	0.2	NA
TDS (mg/L)	306	149

(ii) For discharges of FGD wastewater generated before December 31, 2023, the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed for TSS in § 423.12(b)(11).

(4) *2024 BAT.* (i) Except for those discharges to which paragraphs (g)(3) and (g)(4)(ii) through (iv) of this section applies, there shall be no discharge of pollutants in FGD wastewater.

(A) Dischargers must meet the effluent limitations for FGD wastewater in this paragraph (g)(4)(i) by a date determined by the permitting authority that is as soon as possible beginning July 8, 2024, but no later than December 31, 2029. These effluent limitations apply to the discharge of FGD wastewater generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph (g)(4)(i).

(B) A facility which submits a request under § 423.19(n) may discharge permeate or distillate from an FGD wastewater treatment system designed to achieve the limitations in this paragraph (g)(4)(i) for an additional period of up to one year from the date determined in paragraph (g)(4)(i)(A) of this section.

(ii) For any electric generating unit with a total nameplate capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed for TSS in § 423.12(b)(11).

(iii) For any electric generating unit for which the owner has submitted a certification pursuant to § 423.19(h), the quantity of pollutants discharged in FGD wastewater shall continue to be subject to limitations specified in paragraph (g)(1) or (g)(2)(ii) or (iii) of this section as incorporated into the existing permit.

(A) Where such unit has permanently ceased coal combustion by December 31, 2034, there shall be no discharge of pollutants in FGD wastewater after April 30, 2035.

(B) Where such unit has failed to permanently cease coal combustion by December 31, 2034, there shall be no discharge of pollutants in FGD wastewater after December 31, 2034.

(iv) For FGD wastewater discharged from any coal combustion residual surface impoundment which commences closure pursuant to 40 CFR 257.102(e) after July 8, 2024, the quantity of pollutants in FGD

wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in table 8 to this paragraph (g)(4)(iv).

TABLE 8 TO PARAGRAPH (g)(4)(iv)

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

(h) *Fly ash transport water.* (1) * * *

(ii) *Legacy fly ash transport water.* For fly ash transport water generated before the date determined by the permitting authority, as specified in paragraph (h)(1)(i) of this section, the EPA is declining to establish BAT limitations and is reserving such limitations to be established by the permitting authority on a case-by-case basis using the permitting authority's best professional judgment.

* * * * *

(i) *Flue gas mercury control wastewater.* (1) * * *

(ii) *Legacy flue gas mercury control wastewater.* For flue gas mercury control wastewater generated before the date determined by the permitting authority, as specified in paragraph (i)(1)(i) of this section, the EPA is declining to establish BAT limitations and is reserving such limitations to be established by the permitting authority on a case-by-case basis using the permitting authority's best professional judgment.

* * * * *

(k) *Bottom ash transport water*—(1) *2020 BAT.* (i) Except for those discharges to which paragraph (k)(2) of this section applies, or when the bottom ash transport water is used in the FGD scrubber, there shall be no discharge of pollutants in bottom ash transport water. Dischargers must meet the discharge limitation in this paragraph (k)(1)(i) by a date determined by the permitting authority that is as soon as possible beginning October 13, 2021, but no later than December 31, 2025. The limitation in this paragraph (k)(1)(i) applies to the discharge of bottom ash transport water generated on and after the date determined by the permitting authority for meeting the discharge limitation, as specified in this paragraph (k)(1)(i), until the date determined by the permitting authority for meeting the effluent limitations in paragraph (k)(4) of this section. Except for those discharges to which paragraph (k)(2) of this section applies, whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant (except when it is used in the FGD scrubber), the resulting effluent must comply with the discharge limitation in this paragraph (k)(1)(i). When the bottom ash transport water is used in the FGD scrubber, it ceases to be bottom ash transport water, and instead is FGD wastewater, which must meet the requirements in paragraph (g) of this section.

(ii) For bottom ash transport water generated before the date determined by the permitting authority, as specified in paragraph (k)(1)(i) of this section, the EPA is declining to establish BAT limitations and is reserving such limitations to be established by the permitting authority on a case-by-case basis using the permitting authority's best professional judgment.

(2) *2020 BAT subcategories.* (i)(A) The discharge of pollutants in bottom ash transport water from a properly installed, operated, and maintained bottom ash system is authorized under the following conditions:

(*1*) To maintain system water balance when precipitation-related inflows are generated from storm events exceeding a 10-year storm event of 24-hour or longer duration (*e.g.,* 30-day storm event) and cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment; or

(*2*) To maintain system water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is not feasible; or

(*3*) To maintain system water chemistry where installed equipment at the facility is unable to manage pH, corrosive substances, substances or conditions causing scaling, or fine particulates to below levels which impact system operation or maintenance; or

(*4*) To conduct maintenance not otherwise included in paragraph (k)(2)(i)(A)(*1*), (*2*), or (*3*) of this section and not exempted from the definition of transport water in § 423.11(p), and when water volumes cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment.

(B) The total volume that may be discharged for the activities in paragraph (k)(2)(i)(A) of this section shall be reduced or eliminated to the extent achievable using control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice. The total volume of the discharge authorized in this paragraph (k)(2)(i)(B) shall be determined on a case-by-case basis by the permitting authority and in no event shall such discharge exceed a 30-day rolling average of ten percent of the primary active wetted bottom ash system volume. The volume of daily discharges used to calculate the 30-day rolling average shall be calculated using measurements from flow monitors.

(ii) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts, that is an oil-fired unit, or for which the owner has certified to the permitting authority that it will cease combustion of coal pursuant to § 423.19(g), the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration for TSS listed in § 423.12(b)(4).

(A) Where a unit has certified that it will cease combustion of coal pursuant to § 423.19(g) and such unit has permanently ceased coal combustion by December 31, 2028, there shall be no

discharge of pollutants in bottom ash transport water after April 30, 2029.

(B) Where a unit has certified that it will cease combustion of coal pursuant to § 423.19(g) and such unit has failed to permanently cease coal combustion by December 31, 2028, there shall be no discharge of pollutants in bottom ash transport water after December 31, 2028.

(iii) For bottom ash transport water generated by a low utilization electric generating unit, the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration for TSS listed in § 423.12(b)(4), until the date determined by the permitting authority for meeting the effluent limitations in paragraph (k)(4) of this section, and shall incorporate the elements of a best management practices plan as described in paragraph (k)(3) of this section.

(3) *Best management practices plan.* Where required in paragraph (k)(2)(iii) of this section, the discharger shall prepare, implement, review, and update a best management practices plan for the recycle of bottom ash transport water, and must include:

(i) Identification of the low utilization coal-fired generating units that contribute bottom ash to the bottom ash transport system.

(ii) A description of the existing bottom ash handling system and a list of system components (*e.g.,* remote mechanical drag system, tanks, impoundments, chemical addition). Where multiple generating units share a bottom ash transport system, the plan shall specify which components are associated with low utilization generating units.

(iii) A detailed water balance, based on measurements, or estimates where measurements are not feasible, specifying the volume and frequency of water additions and removals from the bottom ash transport system, including:

(A) Water removed from the BA transport system:

(*1*) To the discharge outfall;

(*2*) To the FGD scrubber system;

(*3*) Through evaporation;

(*4*) Entrained with any removed ash; and

(*5*) To any other mechanisms not specified paragraphs (k)(3)(iii)(A)(*1*) through (*4*) of this section.

(B) Water entering or recycled to the BA transport system:

(*1*) Makeup water added to the BA transport water system.

(*2*) Bottom ash transport water recycled back to the system in lieu of makeup water.

(*3*) Any other mechanisms not specified in paragraphs (k)(3)(iii)(B)(*1*) and (*2*) of this section.

(iv) Measures to be employed by all facilities:

(A) Implementation of a comprehensive preventive maintenance program to identify, repair and replace equipment prior to failures that result in the release of bottom ash transport water.

(B) Daily or more frequent inspections of the entire bottom ash transport water system, including valves, pipe flanges and piping, to identify leaks, spills and other unintended bottom ash transport water escaping from the system, and timely repair of such conditions.

(C) Documentation of preventive and corrective maintenance performed.

(v) Evaluation of options and feasibility, accounting for the associated costs, for eliminating or minimizing discharges of bottom ash transport water, including:

(A) Segregation of bottom ash transport water from other process water.

(B) Minimization of the introduction of stormwater by diverting (*e.g.,* curbing, using covers) storm water to a segregated collection system.

(C) Recycling bottom ash transport water back to the bottom ash transport water system.

(D) Recycling bottom ash transport water for use in the FGD scrubber.

(E) Optimization of existing equipment (*e.g.,* pumps, pipes, tanks) and installing new equipment where practicable to achieve the maximum amount of recycle.

(F) Utilization of ''in-line'' treatment of transport water (*e.g.,* pH control, fines removal) where needed to facilitate recycle.

(vi) Description of the bottom ash recycle system, including all technologies, measures, and practices that will be used to minimize discharge.

(vii) A schedule showing the sequence of implementing any changes necessary to achieve the minimized discharge of bottom ash transport water, including the following:

(A) The anticipated initiation and completion dates of construction and installation associated with the technology components or process modifications specified in the plan.

(B) The anticipated dates that the discharger expects the technologies and process modifications to be fully implemented on a full-scale basis, which in no case shall be later than December 31, 2023.

(C) The anticipated change in discharge volume and effluent quality associated with implementation of the plan.

(viii) Description establishing a method for documenting and demonstrating to the permitting/control authority that the recycle system is well operated and maintained.

(ix) Performance of weekly flow monitoring for the following:

(A) Make up water to the bottom ash transport water system.

(B) Bottom ash transport water sluice flow rate (*e.g.,* to the surface impoundment(s), dewatering bins(s), tank(s), remote mechanical drag system).

(C) Bottom ash transport water discharge to surface water or publicly owned treatment works (POTW).

(D) Bottom ash transport water recycle back to the bottom ash system or FGD scrubber.

(4) *2024 BAT.* (i) Except for those discharges to which paragraphs (k)(4)(ii) through (iv) of this section applies, or when the bottom ash transport water is used in the FGD scrubber, there shall be no discharge of pollutants in bottom ash transport water. Dischargers must meet the discharge limitation in this paragraph (k)(4)(i) by a date determined by the permitting authority that is as soon as possible beginning July 8, 2024, but no later than December 31, 2029. The limitation in this paragraph (k)(4)(i) applies to the discharge of bottom ash transport water generated on and after the date determined by the permitting authority for meeting the discharge limitation, as specified in this paragraph (k)(4)(i).

(ii) For any electric generating unit with a total nameplate generating capacity of less than or equal to 50 megawatts or that is an oil-fired unit, the quantity of pollutants discharged in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of the applicable wastewater times the concentration for TSS listed in § 423.12(b)(4).

(iii) For any electric generating unit for which the owner has submitted a certification pursuant to § 423.19(h), the quantity of pollutants discharged in bottom ash transport water shall continue to be subject to limitations specified in paragraph (k)(1) or (k)(2)(i) or (iii) of this section as incorporated into the existing permit.

(A) Where such unit has permanently ceased coal combustion by December 31, 2034, there shall be no discharge of pollutants in bottom ash transport water after April 30, 2035.

(B) Where such unit has failed to permanently cease coal combustion by December 31, 2034, there shall be no discharge of pollutants in bottom ash transport water after December 31, 2034.

(iv) For bottom ash transport water discharged from any coal combustion residual surface impoundment which commences closure pursuant to 40 CFR 257.102(e) after July 8, 2024, the quantity of pollutants in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in table 10 to this paragraph (k)(4)(iv).

TABLE 10 TO PARAGRAPH (k)(4)(iv)

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

(l) *Combustion residual leachate*—(1) *2024 BAT.* (i) Except for those discharges to which paragraph (l)(1)(i)(B) or (C) or (1)(2) of this section applies, there shall be no discharge of pollutants in combustion residual leachate.

(A) Dischargers must meet the effluent limitations for combustion residual leachate in this paragraph (l)(1)(i) by a date determined by the permitting authority that is as soon as possible beginning July 8, 2024, but no later than December 31, 2029. The effluent limitations in this paragraph (l)(1)(i) apply to the discharge of combustion residual leachate generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph (l)(1)(i).

(B) A facility which submits a request under § 423.19(n) may discharge permeate or distillate from a combustion residual leachate treatment system designed to achieve the limitations in this paragraph (l)(1)(i) for an additional period of up to one year from the date determined in paragraph (l)(1)(i)(A) of this section.

(C) After the retirement of all units at a facility, the quantity of pollutants in combustion residual leachate (CRL) shall not exceed the quantity determined by multiplying the flow of CRL permeate times the concentrations listed in the table 7 to paragraph (g)(3)(i) of this section or the flow of CRL distillate times the concentrations listed in the table following § 423.15(b)(13).

(ii) For combustion residual leachate generated before the date determined by the permitting authority, as specified in paragraph (l)(1)(i) of this section, the EPA is declining to establish BAT limitations and is reserving such limitations to be established by the permitting authority on a case-by-case basis using the permitting authority's best professional judgment.

(2) *2024 BAT subcategories.* (i) Discharges of combustion residual leachate for which the owner has submitted a certification pursuant to § 423.19(h).

(A) Where such unit has permanently ceased coal combustion by December 31, 2034, the quantity of pollutants in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in table 11 to this paragraph (l)(2)(i)(A) by a date determined by the permitting authority that is as soon as possible beginning 120 days after the facility permanently ceases coal combustion, but no later than April 30, 2035.

TABLE 11 TO PARAGRAPH (l)(2)(i)(A)

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

(B) Where such unit has failed to permanently cease coal combustion by December 31, 2034, there shall be no discharge of pollutants in combustion residual leachate after December 31, 2034.

(ii) For discharges of unmanaged combustion residual leachate, the quantity of pollutants in unmanaged combustion residual leachate shall not exceed the quantity determined by multiplying the flow of unmanaged combustion residual leachate times the concentration listed in the table 11 to paragraph (l)(2)(i)(A) of this section.

(A) Dischargers must meet the effluent limitations for unmanaged combustion residual leachate in this paragraph (l)(2)(ii) by a date determined by the permitting authority that is as soon as possible beginning July 8, 2024, but no later than December 31, 2029. The effluent limitations in this paragraph (l)(2)(ii) apply to the discharge of unmanaged combustion residual leachate generated on and after the date determined by the permitting authority for meeting the effluent limitations, as specified in this paragraph (l)(2)(ii).

(B) Discharges of unmanaged combustion residual leachate before the date determined in paragraph (l)(2)(ii)(A) of this section.

(iii) For combustion residual leachate discharged from any coal combustion residual surface impoundment which commences closure pursuant to 40 CFR

257.102(e) after July 8, 2024, the quantity of pollutants in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in table 12 to this paragraph (l)(2)(iii).

TABLE 12 TO PARAGRAPH (l)(2)(iii)

Pollutant or pollutant property	BAT effluent limitations	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

* * * * *

(o) *Transfers.* (1) Transfer between applicable limitations in a permit. Where, in the permit, the permitting authority has included alternative limits subject to eligibility requirements, upon timely notification to the permitting authority under § 423.19(l), a facility can become subject to the alternative limits under the following circumstances:

(i) On or before December 31, 2023, a facility may convert:

(A) From limitations for electric generating units permanently ceasing coal combustion under paragraph (g)(2)(i) or (k)(2)(ii) of this section to limitations for low utilization electric generating units under paragraph (g)(2)(iii) or (k)(2)(iii) of this section; or

(B) From voluntary incentives program limitations under paragraph (g)(3)(i) of this section or generally applicable limitations under paragraph (k)(1)(i) of this section to limitations for low utilization electric generating units under paragraph (g)(2)(iii) or (k)(2)(iii) of this section.

(ii) On or before December 31, 2025, a facility may convert:

(A) From voluntary incentives program limitations under paragraph (g)(3)(i) of this section to limitations for electric generating units permanently ceasing coal combustion under paragraph (g)(2)(i) of this section; or

(B) From limitations for electric generating units permanently ceasing coal combustion under paragraph (g)(2)(i) or (k)(2)(ii) of this section to voluntary incentives program limitations under paragraph (g)(3)(i) of this section or generally applicable limitations under (k)(1)(i) of this section; or

(C) From limitations for low utilization electric generating units under paragraph (g)(2)(iii) or (k)(2)(iii) of this section to generally applicable limitations under paragraph (g)(1)(i) or (k)(1)(i) of this section; or

(D) From limitations for low utilization electric generating units under paragraph (g)(2)(iii) or (k)(2)(iii) of this section to voluntary incentives program limitations under paragraph (g)(3)(i) of this section or generally applicable limitations under paragraph (k)(1)(i) of this section; or

(E) From limitations for low utilization electric generating units under paragraph (g)(2)(iii) or (k)(2)(iii) of this section to limitations for electric generating units permanently ceasing coal combustion under paragraph (g)(2)(i) and (k)(2)(ii) of this section.

(2) A facility must be in compliance with all of its currently applicable requirements to be eligible to file a notice under § 423.19(l) and to become subject to a different set of applicable requirements under paragraph (o)(1) of this section.

(3) Where a facility seeking a transfer under paragraph (o)(1)(ii) of this section is currently subject to more stringent limitations than the limitations being sought, the facility must continue to meet those more stringent limitations.

* * * * *

■ 5. Amend § 423.15 by adding paragraph (c) to read as follows:

§ 423.15 New source performance standards (NSPS).

* * * * *

(c) *2024 NSPS for combustion residual leachate.* (1) Except as provided in paragraph (c)(2) of this section, there shall be no discharge of pollutants in combustion residual leachate (CRL). Whenever CRL is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph (c).

(2) After the retirement of all units at a facility, the quantity of pollutants in CRL shall not exceed the quantity determined by multiplying the flow of CRL permeate times the concentrations listed in table 7 to § 423.13(g)(3)(i) or the flow of CRL distillate times the concentrations listed in the table in paragraph (b)(13) of this section.

* * * * *

■ 6. Amend § 423.16 by revising paragraphs (e) and (g) and adding paragraph (j) to read as follows:

§ 423.16 Pretreatment standards for existing sources (PSES).

* * * * *

(e) *FGD wastewater*—(1) *2020 PSES.* Except as provided for in paragraph (e)(2) of this section, for any electric generating unit with a total nameplate generating capacity of more than 50 megawatts, that is not an oil-fired unit, and that the owner has not certified that it will cease coal combustion pursuant to § 423.19(g), the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in table 3 to this paragraph (e)(1). Dischargers must meet the standards in this paragraph (e)(1) by October 13, 2023, except as provided for in paragraph (e)(2) of this section. The standards in this paragraph (e)(1) apply to the discharge of FGD wastewater generated on and after October 13, 2023.

TABLE 3 TO PARAGRAPH (e)(1)

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	18	8
Mercury, total (ng/L)	103	34
Selenium, total (μg/L)	70	29
Nitrate/nitrite as N (mg/L)	4	3

(2) *2020 PSES subcategories.* (i) For FGD wastewater discharges from a low utilization electric generating unit, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table 4 to paragraph (e)(2)(ii) of this section. Dischargers must meet the standards in this paragraph (e)(2)(i) by October 13, 2023.

(ii) If any low utilization electric generating unit fails to timely recertify that the two year average capacity utilization rating of such an electric generating unit is below 10 percent per year as specified in § 423.19(f), regardless of the reason, within two years from the date such a recertification was required, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table 3 to paragraph (e)(1) of this section.

TABLE 4 TO PARAGRAPH (e)(2)(ii)

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

(3) *2024 PSES.* Except as provided for in paragraph (e)(4) of this section, for any electric generating unit with a total nameplate generating capacity of more than 50 megawatts and that is not an oil-fired unit, there shall be no discharge of pollutants in FGD wastewater. Dischargers must meet the standards in this paragraph (e)(3) by May 9, 2027, except as provided for in paragraph (e)(4) of this section. The standards in this paragraph (e)(3) apply to the discharge of FGD wastewater generated on and after May 9, 2027.

(4) *2024 PSES subcategories.* (i) For any electric generating unit for which the owner has submitted a certification pursuant to § 423.19(h), the quantity of pollutants discharged in FGD wastewater shall continue to be subject to standards specified in paragraph (e)(1) or (2) of this section as incorporated into the existing control mechanism.

(A) Where such unit has permanently ceased coal combustion by December 31, 2034, there shall be no discharge of pollutants in FGD wastewater after April 30, 2035.

(B) Where such unit has failed to permanently cease coal combustion by December 31, 2034, there shall be no discharge of pollutants in FGD wastewater after December 31, 2034.

(ii) For FGD wastewater discharged from any coal combustion residual surface impoundment which commences closure pursuant to 40 CFR 257.102(e) after July 8, 2024, the quantity of pollutants in FGD wastewater shall not exceed the quantity determined by multiplying the flow of FGD wastewater times the concentration listed in the table 5 to this paragraph (e)(4)(ii).

TABLE 5 TO PARAGRAPH (e)(4)(ii)

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

* * * * *

(g) *Bottom ash transport water*—(1) *2020 PSES.* Except for those discharges to which paragraph (g)(2) of this section applies, or when the bottom ash transport water is used in the FGD scrubber, for any electric generating unit with a total nameplate generating capacity of more than 50 megawatts, that is not an oil-fired unit, that is not a low utilization electric generating unit, and that the owner has not certified that the electric generating unit will cease coal combustion pursuant to § 423.19(g), there shall be no discharge of pollutants in bottom ash transport water. The standard in this paragraph (g)(1) applies to the discharge of bottom ash transport water generated on and after October 13, 2023. Except for those discharges to which paragraph (g)(2) of this section applies, whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant (except when it is used in the FGD scrubber), the resulting effluent must comply with the discharge standard in this paragraph (g)(1). When the bottom ash transport water is used in the FGD scrubber, the quantity of pollutants in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in table 3 to paragraph (e)(1) of this section.

(2) *2020 PSES subcategories.* (i) The discharge of pollutants in bottom ash transport water from a properly installed, operated, and maintained bottom ash system is authorized under the following conditions:

(A) To maintain system water balance when precipitation-related inflows are generated from a 10-year storm event of 24-hour or longer duration (*e.g.,* 30-day storm event) and cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment; or

(B) To maintain system water balance when regular inflows from wastestreams other than bottom ash transport water exceed the ability of the bottom ash system to accept recycled water and segregating these other wastestreams is feasible; or

(C) To maintain system water chemistry where current operations at the facility are unable to currently manage pH, corrosive substances, substances or conditions causing scaling, or fine particulates to below levels which impact system operation or maintenance; or

(D) To conduct maintenance not otherwise included in paragraphs (g)(2)(i)(A), (B), or (C) of this section and not exempted from the definition of transport water in § 423.11(p), and when water volumes cannot be managed by installed spares, redundancies, maintenance tanks, and other secondary bottom ash system equipment.

(ii) The total volume that may be discharged to a POTW for the activities in paragraphs (g)(2)(i)(A) through (D) of this section shall be reduced or eliminated to the extent achievable as determined by the control authority. The control authority may also include control measures (including best management practices) that are technologically available and economically achievable in light of best industry practice. In no event shall the total volume of the discharge exceed a 30-day rolling average of ten percent of the primary active wetted bottom ash system volume. The volume of daily discharges used to calculate the 30-day rolling average shall be calculated using measurements from flow monitors.

(iii) For bottom ash transport water generated by a low utilization electric generating unit, the quantity of pollutants discharged in bottom ash transport water shall incorporate the elements of a best management practices plan as described in § 423.13(k)(3).

(3) *2024 PSES.* Except for those discharges to which paragraph (g)(4) of this section applies, for any electric generating unit with a total nameplate generating capacity of more than 50 megawatts, that is not an oil-fired unit, there shall be no discharge of pollutants in bottom ash transport water. The standard in this paragraph (g)(3) applies to the discharge of bottom ash transport water generated on and after May 9, 2027. Except for those discharges to which paragraph (g)(4) of this section applies, whenever bottom ash transport water is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph (g)(3).

(4) *2024 PSES subcategories.* (i) For any electric generating unit for which the owner has submitted a certification pursuant to § 423.19(h), the quantity of pollutants discharged in bottom ash transport water shall continue to be subject to standards specified in paragraph (g)(1) or (2) as incorporated into the existing control mechanism.

(A) Where such unit has permanently ceased coal combustion by December 31, 2034, there shall be no discharge of pollutants in bottom ash transport water after April 30, 2035.

(B) Where such unit has failed to permanently cease coal combustion by December 31, 2034, there shall be no discharge of pollutants in bottom ash transport water after December 31, 2034.

(ii) For bottom ash transport water discharged from any coal combustion residual surface impoundment which commences closure pursuant to 40 CFR 257.102(e) after July 8, 2024, the quantity of pollutants in bottom ash transport water shall not exceed the quantity determined by multiplying the flow of bottom ash transport water times the concentration listed in table 6 to this paragraph (g)(4)(ii).

TABLE 6 TO PARAGRAPH (g)(4)(ii)

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (µg/L)	11	8
Mercury, total (ng/L)	788	356

* * * * *

(j) *Combustion residual leachate*—(1) *2024 PSES.* (i) Except for those discharges to which paragraph (j)(2) or (j)(1)(ii) of this section applies, there shall be no discharge of pollutants in combustion residual leachate. The standard in this paragraph (j)(1)(i) applies to the discharge of combustion residual leachate generated on and after May 9, 2027. Except for those discharges to which paragraph (j)(2) of this section

applies, whenever combustion residual leachate is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph (j)(1)(i).

(ii) After the retirement of all units at a facility, the quantity of pollutants in CRL shall not exceed the quantity determined by multiplying the flow of CRL permeate times the concentrations listed in the table 7 to § 423.13(g)(3)(i) or the flow of CRL distillate times the concentrations listed in the table in § 423.15(b)(13).

(2) *2024 PSES subcategories.* (i) Except as described in paragraph (j)(2)(i)(A) of this section, the EPA is declining to establish PSES for electric generating units for which the owner has submitted a certification pursuant to § 423.19(h) and is reserving such standards to be established by the control authority on a case-by-case.

(A) Where such unit has permanently ceased coal combustion by December 31, 2034, the quantity of pollutants in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in the table 7 to this paragraph (j)(2)(i)(A) no later than April 30, 2035.

TABLE 7 TO PARAGRAPH (j)(2)(i)(A)

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

(B) Where such unit has failed to permanently cease coal combustion by December 31, 2034, there shall be no discharge of pollutants in FGD wastewater after December 31, 2034.

(ii) For combustion residual leachate discharged from any coal combustion residual surface impoundment which commences closure pursuant to 40 CFR 257.102(e) after July 8, 2024, the quantity of pollutants in combustion residual leachate shall not exceed the quantity determined by multiplying the flow of combustion residual leachate times the concentration listed in table 8 to this paragraph (j)(2)(ii).

TABLE 8 TO PARAGRAPH (j)(2)(ii)

Pollutant or pollutant property	PSES	
	Maximum for any 1 day	Average of daily values for 30 consecutive days shall not exceed
Arsenic, total (μg/L)	11	8
Mercury, total (ng/L)	788	356

■ 7. Amend § 423.17 by adding paragraph (c) to read as follows:

§ 423.17 Pretreatment standards for new sources (PSNS).

* * * * *

(c) *2024 PSNS for combustion residual leachate.* (1) Except as provided in paragraph (c)(2) of this section, there shall be no discharge of pollutants in combustion residual leachate (CRL). Whenever CRL is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the discharge standard in this paragraph (c)(1).

(2) After the retirement of all units at a facility, the quantity of pollutants in CRL shall not exceed the quantity determined by multiplying the flow of CRL permeate times the concentrations listed in table 7 to § 423.13(g)(3)(i) or the flow of CRL distillate times the concentrations listed in the table in § 423.15(b)(13).

■ 8. Revise § 423.18 to read as follows:

§ 423.18 Permit conditions.

All permits subject to this part shall include the following permit conditions:

(a) An electric generating unit shall qualify as a low utilization electric generating unit, permanently ceasing the combustion of coal by December 31, 2028, or permanently ceasing the combustion of coal by December 31, 2034, if such qualification would have been demonstrated absent the following qualifying event:

(1) An emergency order issued by the Department of Energy under section 202(c) of the Federal Power Act;

(2) A reliability must run agreement issued by a Public Utility Commission; or

(3) Any other reliability-related order, energy emergency alert, or agreement issued by a competent electricity regulator (*e.g.,* an independent system operator) which results in that electric generating unit operating in a way not contemplated when the certification was made; or

(4) The operation of the electric generating unit was necessary for load balancing in an area subject to a declaration under 42 U.S.C. 5121 *et seq.,* that there exists:

(i) An ''Emergency''; or

(ii) A ''Major Disaster''; and

(iii) That load balancing was due to the event that caused the ''Emergency'' or ''Major Disaster'' in paragraphs

(a)(4)(i) and (ii) of this section to be declared.

(b) Any facility providing the required documentation pursuant to § 423.19(i) may avail itself of the protections of the permit condition in paragraph (a) of this section.

(c) A facility discharging permeate or distillate from an FGD wastewater or combustion residual leachate treatment system and satisfying § 423.19(n) shall be deemed to meet the following requirements:

(1) The FGD wastewater requirements of § 423.13(g)(4) for up to one year after the date determined pursuant to § 423.11(t); and

(2) The combustion residual leachate requirements of § 423.13(l)(1) for up to one year after the date determined pursuant to § 423.11(t).

■ 9. Revise and republish § 423.19 to read as follows:

§ 423.19 Reporting and recordkeeping requirements.

(a) *In general.* Discharges subject to this part must comply with the reporting requirements in this section.

(b) *Signature and certification.* Unless otherwise provided in this section, all certifications and recertifications required in this part must be signed and certified pursuant to 40 CFR 122.22 for direct dischargers or 40 CFR 403.12(l) for indirect dischargers.

(c) *Publicly accessible internet site requirements.* (1) Except as provided in paragraph (c)(2) of this section, each facility subject to one or more of the reporting requirements in paragraphs (d) through (o) of this section must maintain a publicly accessible internet site (ELG website) containing the information specified in paragraphs (d) through (o), if applicable. This website shall be titled ''ELG Rule Compliance Data and Information.'' The facility must ensure that all information required to be posted is immediately available to anyone visiting the site, without requiring any prerequisite, such as registration or a requirement to submit a document request. All required information must be clearly identifiable and must be able to be immediately downloaded by anyone accessing the site in a format that enables additional analysis (*e.g.,* comma-separated values text file format). When the facility initially creates, or later changes, the web address (*i.e.,* Uniform Resource Locator (URL)) at any point, they must notify EPA via the ''contact us'' form on EPA's Effluent Guidelines website and the permitting authority or control authority within 14 days of creating the website or making the change. The facility's ELG website must also have a ''contact us'' form or a specific email address posted on the website for the public to use to submit questions and issues relating to the availability of information on the website.

(2)(i) When an owner or operator subject to this section already maintains a ''CCR Rule Compliance Data and Information'' website pursuant to 40 CFR 257.107, the postings required under this section may be made to the existing ''CCR Rule Compliance Data and Information'' website and shall be delineated under a separate heading that shall state ''ELG Rule Compliance Data and Information.'' When electing to use an existing website pursuant to this paragraph (c)(2), the facility shall notify EPA via the ''contact us'' form on EPA's Effluent Guidelines website and the permitting authority or control authority no later than July 8, 2024, or upon first becoming subject to paragraphs (d) through (o) of this section, whichever is later.

(ii) When the same owner or operator is subject to the provisions of this part for multiple facilities, the owner or operator may comply with the requirements of this section by using the same internet site for multiple facilities provided the ELG website clearly delineates information by the name of each facility.

(3) Unless otherwise required in this section, the information required to be posted to the ELG website must be made available to the public for at least 10 years following the date on which the information was first posted to the ELG website, or the length of the permit plus five years, whichever is longer. All required information must be clearly identifiable and must be able to be immediately downloaded by anyone accessing the site in a format that enables additional analysis (*e.g.,* comma-separated values text file format).

(4) Unless otherwise required in this section, the information must be posted to the ELG website:

(i) Within 30 days of submitting the information to the permitting authority or control authority; or

(ii) Where information was submitted to the permitting authority or control authority prior to July 8, 2024, by July 8, 2024.

(d) *Requirements for facilities discharging bottom ash transport water under this part*—(1) *Certification statement.* For sources seeking to discharge bottom ash transport water pursuant to § 423.13(k)(2)(i) or (g)(2)(i), an initial certification shall be submitted to the permitting authority by the as soon as possible date determined under § 423.11(t), or the control authority by October 13, 2023, in the case of an indirect discharger.

(2) *Signature and certification.* The certification statement must be signed and certified by a professional engineer.

(3) *Contents.* An initial certification shall include the following:

(i) A statement that the professional engineer is a licensed professional engineer.

(ii) A statement that the professional engineer is familiar with the requirements in this part.

(iii) A statement that the professional engineer is familiar with the facility.

(iv) The primary active wetted bottom ash system volume in § 423.11(aa).

(v) Material assumptions, information, and calculations used by the certifying professional engineer to determine the primary active wetted bottom ash system volume.

(vi) A list of all potential discharges under § 423.13(k)(2)(i)(A)(*1*) through (*4*) or § 423.16(g)(2)(i)(A) through (D), the expected volume of each discharge, and the expected frequency of each discharge.

(vii) Material assumptions, information, and calculations used by the certifying professional engineer to determine the expected volume and frequency of each discharge including a narrative discussion of why such water cannot be managed within the system and must be discharged.

(viii) A list of all wastewater treatment systems at the facility currently, or otherwise required by a date certain under this section.

(ix) A narrative discussion of each treatment system including the system type, design capacity, and current or expected operation.

(e) *Requirements for a bottom ash best management practices plan*—(1) *Initial and annual certification statement.* For sources required to develop and implement a best management practices plan pursuant to § 423.13(k)(3), an initial certification shall be made to the permitting authority with a permit application or within two years of October 13, 2021, whichever is later, or to the control authority no later than October 13, 2023, in the case of an indirect discharger, and an annual recertification shall be made to the permitting authority, or control authority in the case of an indirect discharger, within 60 days of the anniversary of the original plan.

(2) *Signature and certification.* The certification statement must be signed and certified by a professional engineer.

(3) *Contents for initial certification.* An initial certification shall include the following:

(i) A statement that the professional engineer is a licensed professional engineer.

(ii) A statement that the professional engineer is familiar with the requirements in this part.

(iii) A statement that the professional engineer is familiar with the facility.

(iv) The best management practices plan.

(v) A statement that the best management practices plan is being implemented.

(4) *Additional contents for annual certification.* In addition to the required contents of the initial certification in paragraph (e)(3) of this section an annual certification shall include the following:

(i) Any updates to the best management practices plan.

(ii) An attachment of weekly flow measurements from the previous year.

(iii) The average amount of recycled bottom ash transport water in gallons per day.

(iv) Copies of inspection reports and a summary of preventative maintenance performed on the system.

(v) A statement that the plan and corresponding flow records are being maintained at the office of the plant.

(f) *Requirements for low utilization electric generating units*—(1) *Notice of Planned Participation.* For sources seeking to qualify as a low utilization electric generating units, a Notice of Planned Participation shall be submitted to the permitting authority or control authority no later than October 13, 2021.

(2) *Contents.* A Notice of Planned Participation shall identify the potential low utilization electric generating unit. The notice shall also include a statement of at least two years' capacity utilization rating data for the most recent two years of operation of each low utilization electric generating unit and a statement that the facility has a good faith belief that each low utilization electric generating unit will continue to operate at the required capacity utilization rating. Where the most recent capacity utilization rating does not meet the low utilization electric generating unit requirement, a discussion of the projected future utilization shall be provided, including material data and assumptions used to make that projection.

(3) *Initial and annual certification statement.* For sources seeking to qualify as a low utilization electric generating unit under this part, an initial certification shall be made to the permitting authority, or to the control authority in the case of an indirect discharger, no later than December 31, 2023, and an annual recertification shall be made to the permitting authority, or control authority in the case of an indirect discharger, within 60 days of submitting annual electricity production data to the Energy Information Administration.

(4) *Contents.* A certification or annual recertification shall be based on the information submitted to the Energy Information Administration and shall include copies of the underlying forms submitted to the Energy Information Administration, as well as any supplemental information and calculations used to determine the two year average annual capacity utilization rating.

(g) *Requirements for units that will achieve permanent cessation of coal combustion by December 31, 2028*—(1) *Notice of Planned Participation.* For sources seeking to qualify as an electric generating unit that will achieve permanent cessation of coal combustion by December 31, 2028, under this part, a Notice of Planned Participation shall be made to the permitting authority, or to the control authority in the case of an indirect discharger, no later than June 27, 2023.

(2) *Contents.* A Notice of Planned Participation shall identify the electric generating units intended to achieve the permanent cessation of coal combustion. A Notice of Planned Participation shall include the expected date that each electric generating unit is projected to achieve permanent cessation of coal combustion, whether each date represents a retirement or a fuel conversion, whether each retirement or fuel conversion has been approved by a regulatory body, and what the relevant regulatory body is. The Notice of Planned Participation shall also include a copy of the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, certification of electric generating unit cessation under 40 CFR 257.103(b), or other documentation supporting that the electric generating unit will permanently cease the combustion of coal by December 31, 2028. The Notice of Planned Participation shall also include, for each such electric generating unit, a timeline to achieve the permanent cessation of coal combustion. Each timeline shall include interim milestones and the projected dates of completion.

(3) *Annual progress report.* Annually after submission of the Notice of Planned Participation in paragraph (g)(1) of this section, a progress report shall be filed with the permitting authority, or control authority in the case of an indirect discharger.

(4) *Contents.* An annual progress report shall detail the completion of any interim milestones listed in the Notice of Planned Participation since the previous progress report, provide a narrative discussion of any completed, missed, or delayed milestones, and provide updated milestones. An annual progress report shall also include one of the following:

(i) A copy of the official suspension filing (or equivalent filing) made to the facility's reliability authority detailing the conversion to a fuel source other than coal;

(ii) A copy of the official retirement filing (or equivalent filing) made to the facility's reliability authority which must include a waiver of recission rights; or

(iii) An initial certification, or recertification for subsequent annual progress reports, containing either a statement that the facility will make the filing required in paragraph (g)(4)(i) of this section or a statement that the facility will make the filing required in paragraph (g)(4)(ii) of this section. The certification or recertification must include the estimated date that such a filing will be made.

(iv) A facility shall not include a certification or recertification under paragraph (g)(4)(iii) of this section in the final annual progress report submitted prior to permanent cessation of coal combustion. Rather, this final annual progress report must include the filing under paragraph (g)(4)(i) or (ii) of this section.

(h) *Requirements for units that will achieve permanent cessation of coal combustion by December 31, 2034*—(1) *Notice of Planned Participation.* For sources seeking to qualify as an electric generating unit that will achieve permanent cessation of coal combustion by December 31, 2034, under this part, a Notice of Planned Participation shall be made to the permitting authority, or to the control authority in the case of an indirect discharger, no later than December 31, 2025.

(2) *Contents.* A Notice of Planned Participation shall identify the electric generating units intended to achieve the permanent cessation of coal combustion. A Notice of Planned Participation shall include the expected date that each electric generating unit is projected to achieve permanent cessation of coal combustion, whether each date represents a retirement or a fuel conversion, whether each retirement or fuel conversion has been approved by a regulatory body, and what the relevant regulatory body is.

The Notice of Planned Participation shall also include a copy of the most recent integrated resource plan for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, or other documentation supporting that the electric generating unit will permanently cease the combustion of coal by December 31, 2034. The Notice of Planned Participation shall also include, for each such electric generating unit, a timeline to achieve the permanent cessation of coal combustion. Each timeline shall include interim milestones and the projected dates of completion. Finally, the Notice of Planned Participation shall also include, for each such electric generating unit, a certification statement that the facility is in compliance with the following limitations or standards:

(i) The applicable limitations or standards for FGD wastewater in § 423.13(g)(1) or (g)(2)(ii) or (iii) or § 423.16(e)(1) or (2); and

(ii) The applicable limitations or standards for bottom ash transport water in § 423.13(k)(1) or (k)(2)(i) or (iii) or § 423.16(g)(1) or (2).

(3) *Annual progress report.* Annually after submission of the Notice of Planned Participation in paragraph (h)(1) of this section, a progress report shall be filed with the permitting authority, or control authority in the case of an indirect discharger.

(4) *Contents.* An annual progress report shall detail the completion of any interim milestones listed in the Notice of Planned Participation since the previous progress report, provide a narrative discussion of any completed, missed, or delayed milestones, and provide updated milestones. An annual progress report shall also include one of the following:

(i) A copy of the official suspension filing (or equivalent filing) made to the facility's reliability authority detailing the conversion to a fuel source other than coal;

(ii) A copy of the official retirement filing (or equivalent filing) made to the facility's reliability authority which must include a waiver of recission rights; or

(iii) An initial certification, or recertification for subsequent annual progress reports, containing either a statement that the facility will make the filing required in paragraph (h)(4)(i) of this section or a statement that the facility will make the filing required in paragraph (h)(4)(ii) of this section. The certification or recertification must include the estimated date that such a filing will be made.

(iv) A facility shall not include a certification or recertification under paragraph (h)(4)(iii) of this section in the final annual progress report submitted prior to permanent cessation of coal combustion. Rather, this final annual progress report must include the filing under paragraph (h)(4)(i) or (ii) of this section.

(i) *Requirements for facilities seeking protections under this part*—(1) *Certification statement.* For sources seeking to apply the protections of the permit conditions in § 423.18(a), and for each instance that § 423.18(a) is applied, a one-time certification shall be submitted to the permitting authority, or control authority in the case of an indirect discharger, no later than:

(i) In the case of an order or agreement under § 423.18(a)(1), 30 days from receipt of the order or agreement attached pursuant to paragraph (i)(2)(ii) of this section; or

(ii) In the case of an ''Emergency'' or ''Major Disaster'' under § 423.18(a)(2), 30 days from the date that a load balancing need arose.

(2) *Contents.* A certification statement must include the following:

(i) The qualifying event from the list in § 423.18(a), the individual or entity that issued or triggered the event, and the date that such an event was issued or triggered.

(ii) A copy of any documentation of the qualifying event from the individual or entity listed under paragraph (i)(2)(i) of this section, or, where such documentation does not exist, other documentation with indicia of reliability for the permitting authority to confirm the qualifying event.

(iii) An analysis and accompanying narrative discussion which demonstrates that an electric generating unit would have qualified for the subcategory at issue absent the event detailed in paragraph (i)(2)(i) of this section, including the material data, assumptions, and methods used.

(3) *Termination of need statement.* For sources filing a certification statement under paragraph (i)(1) of this section, and for each such certification statement, a one-time termination of need statement shall be submitted to the permitting authority, or control authority in the case of an indirect discharger, no later than 30 days from when the source is no longer subject to increased production from the qualifying event.

(4) *Contents.* A termination of need statement must include a narrative discussion including the date the qualifying event terminated, or if it has not terminated, why the source believes the capacity utilization will no longer be elevated to a level requiring the protection of § 423.18.

(j) *Requirements for facilities voluntarily meeting limits in this part*—(1) *Notice of Planned Participation.* For sources opting to comply with the Voluntary Incentives Program requirements of § 423.13(g)(3)(i) by December 31, 2028, a Notice of Planned Participation shall be made to the permitting authority no later than October 13, 2021.

(2) *Contents.* A Notice of Planned Participation shall identify the facility opting to comply with the Voluntary Incentives Program requirements of § 423.13(g)(3)(i), specify what technology or technologies are projected to be used to comply with those requirements, and provide a detailed engineering dependency chart and accompanying narrative demonstrating when and how the system(s) and any accompanying disposal requirements will be achieved by December 31, 2028.

(3) *Annual progress report.* After submission of the Notice of Planned Participation in paragraph (j)(1) of this section, a progress report shall be filed with the permitting authority, or control authority in the case of an indirect discharger.

(4) *Contents.* An annual progress report shall detail the completion of interim milestones presented in the engineering dependency chart from the Notice of Planned Participation since the previous progress report, provide a narrative discussion of completed, missed, or delayed milestones, and provide updated milestones.

(5) *Rollover certification.* Where, prior to October 13, 2020, a discharger has already provided a notice to the permitting authority of opting to comply with the Voluntary Incentives Program requirements of § 423.13(g)(3)(i), such notice will satisfy paragraph (j)(1) of this section. However, where details required by paragraph (j)(2) of this section were missing from the previously provided notice, those details must be provided in the first annual progress report, no later than October 13, 2021.

(k) *Requirements for facilities with discharges of unmanaged combustion residual leachate*—(1) *Annual combustion residual leachate monitoring report.* In addition to reporting pursuant to 40 CFR part 127, each facility with discharges of unmanaged combustion residual leachate meeting the definition in § 423.11(ff)(1) shall file an annual combustion residual leachate monitoring report each calendar year to the permitting authority.

(2) *Contents.* The annual combustion residual leachate monitoring report shall provide the following monitoring data for each pollutant listed in table 1 to paragraph (k)(2)(v) of this section. For paragraphs (k)(2)(ii) and (iii) of this section the report shall also describe the location of monitoring wells, screening depth, and frequency of sampling. The report shall include summary statistics including monthly minimum, maximum, and average concentrations for each pollutant. The report shall be supported by an appendix of all samples.

(i) A list of coal combustion residual landfills and surface impoundments which the permitting authority has determined are point sources with functional equivalent direct discharges.

(ii) Groundwater monitoring data as the combustion residual leachate leaves each of the landfills or surface impoundment listed in paragraph (k)(2)(i) of this section.

(iii) Groundwater monitoring at the point the combustion residual leachate enters a surface waterbody.

(iv) Effluent monitoring data reported pursuant to 40 CFR part 127.

(v) Summary statistics for the data described in paragraphs (k)(2)(ii) through (iv) of this section including the monthly average and daily maximum of each pollutant in the table 1 to this paragraph (k)(2)(v) and a comparison to any limitation in § 423.13(l)(2)(ii).

TABLE 1 TO PARAGRAPH (k)(2)(v)

BAT Treated Pollutants in Combustion Residual Leachate	
Antimony	Magnesium
Arsenic	Manganese
Barium	Mercury
Beryllium	Molybdenum
Cadmium	Nickel
Chromium	Thallium
Cobalt	Titanium
Copper	Vanadium
Lead	Zinc

(l) *Requirements for facilities seeking to transfer between applicable limitations in a permit under this part*—(1) *Notice of Planned Participation.* For sources which have filed a Notice of Planned Participation under paragraph (f)(1), (g)(1), or (j)(1) of this section and intend to make changes that would qualify them for a different set of requirements under § 423.13(o), a Notice of Planned Participation shall be made to the permitting authority, or to the control authority in the case of an indirect discharger, no later than the dates stated in § 423.13(o)(1).

(2) *Contents.* A Notice of Planned Participation shall include a list of the electric generating units for which the source intends to change compliance alternatives. For each such electric generating unit, the notice shall list the specific provision under which this transfer will occur, the reason such a transfer is warranted, and a narrative discussion demonstrating that each electric generating unit will be able to maintain compliance with the relevant provisions.

(m) *Notice of material delay*—(1) *Notice.* Within 30 days of experiencing a material delay in the milestones set forth in paragraph (g)(2), (h)(2), or (j)(2) of this section and where such a delay may preclude permanent cessation of coal combustion or compliance with the voluntary incentives program limitations by December 31, 2028, a facility shall file a notice of material delay with the permitting authority, or control authority in the case of an indirect discharger.

(2) *Contents.* The contents of such a notice shall include the reason for the delay, the projected length of the delay, and a proposed resolution to maintain compliance.

(n) *Requirements for facilities seeking a one-year flexibility to discharge permeate or distillate from an FGD wastewater or combustion residual leachate treatment system designed to achieve limitations in this part*—(1) *Initial request letter.* When filing a permit application or permit modification request, a facility seeking to discharge permeate or distillate during the first year of operations after the date determined in § 423.13(g)(4)(i)(A) or (l)(1)(i)(A) shall include a letter requesting this flexibility from the permitting authority. The initial request letter shall detail the expected type, frequency, duration, and necessity of discharge. The initial request letter shall also state that this period of discharge was not included for consideration in establishing the applicability timing under § 423.11(t)(3).

(2) *Discharge monitoring and reporting.* Upon inclusion in the permit of the flexibility to discharge the permeate or distillate as requested in paragraph (n)(1) of this section, the permitting authority shall also extend any existing monitoring and reporting requirements (*e.g.,* arsenic monitoring).

(o) *Certification for wastewater generated by a 10-year, 24-hour or longer duration storm event*—(1) *Storm Event Discharge Certification Statement.* For sources seeking to discharge low volume wastewater which would otherwise be considered FGD wastewater, bottom ash transport water, or combustion residual leachate but for a storm event exceeding a 10-year, 24-hour or longer duration storm event, a Storm Event Discharge Certification Statement shall be submitted to the permitting authority, or control authority in the case of an indirect discharger, no later than five business days from the last discharge.

(2) *Signature and certification.* The certification statement must be signed and certified by a professional engineer.

(3) *Contents.* A Storm Event Discharge Certification shall include the following:

(i) A statement that the professional engineer is a licensed professional engineer.

(ii) A statement that the professional engineer is familiar with the requirements in this part.

(iii) A statement that the professional engineer is familiar with the facility.

(iv) A statement that the facility experienced a storm event exceeding a 10-year, 24-hour or longer duration, including specifics of the actual storm event that are sufficient for a third party to verify the accuracy of the statement.

(v) A statement that a discharge of low volume wastewater that would otherwise meet the definition of FGD wastewater, bottom ash transport water, or combustion residual leachate was necessary, including a list of the best management practices at the site and a narrative discussion of the ability of on-site equipment and practices to manage the wastewater.

(vi) The duration and volume of any such discharge.

(vii) A statement that the discharge does not otherwise violate any other limitation or permit condition.

[FR Doc. 2024–09185 Filed 5–8–24; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL REGISTER

Vol. 89 Thursday,
No. 91 May 9, 2024

Part VI

Department of the Interior

Bureau of Land Management

43 CFR Parts 1600 and 6100
Conservation and Landscape Health; Final Rule

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

43 CFR Parts 1600 and 6100

[BLM_HQ_FRN_MO450017935]

RIN 1004–AE92

Conservation and Landscape Health

AGENCY: Bureau of Land Management, Interior.

ACTION: Final rule.

SUMMARY: The Bureau of Land Management (BLM) promulgates this final rule, pursuant to the Federal Land Policy and Management Act of 1976 (FLPMA), as amended, and other relevant authorities, to advance the BLM's multiple use and sustained yield mission by prioritizing the health and resilience of ecosystems across public lands. To support ecosystem health and resilience, the rule provides that the BLM will protect intact landscapes, restore degraded habitat, and make informed management decisions based on science and data. To support these activities, the rule applies land health standards to all BLM-managed public lands and uses, codifies conservation tools to be used within FLPMA's multiple-use framework, and revises existing regulations to better meet FLPMA's requirement that the BLM prioritize designating and protecting areas of critical environmental concern (ACECs). The rule also provides an overarching framework for multiple BLM programs to facilitate ecosystem resilience on public lands.

DATES: The final rule is effective on June 10, 2024.

FOR FURTHER INFORMATION CONTACT: Patricia Johnston, Project Manager for the Conservation and Landscape Health Rule, at 541–600–9693, for information relating to the substance of the final rule. Individuals in the United States who are deaf, deafblind, or hard of hearing, or who have a speech disability, may dial 711 (TTY, TDD, or TeleBraille) to access telecommunications relay services. Individuals outside the United States should use the relay services offered within their country to make international calls to the point-of-contact in the United States.

SUPPLEMENTARY INFORMATION:

I. Executive Summary
II. Background
III. Section-by-Section Discussion of the Final Rule and Revisions From the Proposed Rule
IV. Response to Public Comments
V. Procedural Matters

I. Executive Summary

Under FLPMA, the principles of multiple use and sustained yield govern the BLM's stewardship of public lands, unless otherwise provided by law. The BLM's ability to manage for multiple use and sustained yield of public lands depends on the resilience of ecosystems across those lands—that is, the ability of the ecosystems to withstand disturbance. Ecosystems that collapse due to disturbance cannot deliver ecosystem services, such as clean air and water, food and fiber, wildlife habitat, natural carbon storage, and more. Establishing and safeguarding resilient ecosystems has become imperative as the public lands experience adverse impacts from climate change and as the BLM works to ensure public lands and ecosystem services benefit human communities. The Conservation and Landscape Health Rule establishes the policy for the BLM to build and maintain the resilience of ecosystems on public lands in three primary ways: (1) protecting the most intact, functioning landscapes; [1] (2) restoring degraded habitat and ecosystems; and (3) using science and data as the foundation for management decisions across all plans and programs.

The rule establishes a definition of ''conservation'' that encompasses both protection and restoration actions,[2] recognizing that the BLM must protect intact natural landscapes and restore degraded landscapes to achieve ecosystem resilience. To support efforts to protect and restore public lands, the rule clarifies that conservation is a use on par with other uses of the public lands under FLPMA's multiple-use and sustained-yield mandate. Recognizing that public land conservation is incompatible with a ''one size fits all'' approach, the rule identifies multiple conservation tools to be used where appropriate, including protection of intact landscapes, restoration and mitigation planning, and ACEC designation. Consistent with how the BLM promotes and administers other uses, the rule establishes a durable mechanism—mitigation and restoration leasing—to facilitate both mitigation and restoration on the public lands, while providing opportunities to engage the public in the management of public lands for this purpose. Achieving ecosystem resilience will require, to some extent, the protection of intact landscapes. The goal of the rule is to provide a decision support and prioritization framework for the BLM as it seeks to identify where such protection is appropriate. The rule does not prioritize conservation above other uses; instead, it provides for considering and, where appropriate, implementing or authorizing conservation as one of the many uses managed under FLPMA, consistent with the statute's plain language.

The final rule also clarifies throughout that its provisions should be implemented in a manner that supports land use planning decisions and objectives that emphasize specific uses in specific areas. The Desert Renewable Energy Conservation Plan, for example, identifies Development Focus Areas and conservation areas, as well as conservation and management actions to mitigate the effects of renewable energy development. The 2015 Greater Sage-grouse Plans provide more protections for the most valuable Priority Habitat Management Areas while permitting more activities and related impacts in General Habitat Management Areas. The West-wide Energy Corridors designated by the BLM are identified as areas that are suitable for large transmission lines or pipelines, subject to site-specific analysis of proposed projects and required conditions to avoid or minimize adverse impacts. This preamble and the rule text raise as an example throughout areas that are managed for recreation or degraded lands prioritized for development. The use of this example is not meant to imply that the Bureau permits development only on degraded land.

This final rule does not alter the manner in which the BLM makes or implements these types of land use planning decisions and recognizes how managing for ecosystem resilience across a landscape can incorporate conservation and development, as well as other uses. This recognition is reflected in the rule's approach to identifying and managing areas for landscape intactness, prioritizing areas for restoration, and evaluating land health to inform decision-making.

[1] This rule defines ''intact landscape'' to mean ''a relatively unfragmented landscape free of local conditions that could permanently or significantly disrupt, impair, or degrade the landscape's composition, structure, or function. Intact landscapes are large enough to maintain native biological diversity, including viable populations of wide-ranging species. Intact landscapes provide critical ecosystem services and are resilient to disturbance and environmental change and thus may be prioritized for conservation action. For example, an intact landscape would have minimal fragmentation from roads, fences, and dams; low densities of agricultural, urban, and industrial development; and minimal pollution levels.''

[2] In this rule, conservation is a use; protection and restoration are tools to achieve conservation. Protection is not synonymous with preservation; rather, it allows for active management or other uses consistent with multiple use and sustained yield principles.

The BLM's efforts to protect and restore landscapes and ecosystems and make informed planning, permitting, and program decisions rest on the agency's ability to assess land health conditions and consider those conditions when making decisions. The rule therefore modifies existing BLM practice by applying the fundamentals of land health and related standards and guidelines to all BLM-managed public lands and uses, not just grazing (see § 6103.1(a)). This broad application includes uses, such as oil and gas development and renewable energy generation, that are likely to result in at least local impacts to land health. This rule requires the BLM to take ''appropriate action'' where a specific land use is a factor in failing to achieve land health, but what constitutes ''appropriate action'' may be constrained in a given case both by law and the applicable resource management plan (RMP). For example, where lands are available for solar development under the RMP, options for taking ''appropriate action'' to address land health would not include prohibiting solar development, but may include measures to avoid, minimize, or compensate for impacts from solar development. In general, assessments of land health are intended to inform how uses are managed, rather than if they occur, by providing accurate data on current conditions. In implementing the fundamentals of land health, the rule codifies the need across BLM programs to use high-quality information to prepare land health assessments and evaluations and make determinations about land health condition.

The rule reiterates the importance of meaningful consultation during decision-making processes with Tribes and Alaska Native Corporations on issues that affect their interests, as determined by the Tribes. It requires the BLM to respect and incorporate Indigenous Knowledge into management decisions for ecosystem resilience and directs the BLM to seek opportunities for Tribal co-stewardship of intact landscapes and other lands and ecosystems, consistent with agency and departmental guidance.

Finally, the rule amends the existing ACEC regulations to better assist the BLM in carrying out FLPMA's requirement to give priority to the designation and protection of ACECs. The regulatory changes elaborate on the role of ACECs as the principal administrative designation for protecting important natural, cultural, and scenic resources, and they establish a more comprehensive framework for the BLM to identify, evaluate, and consider special management attention for ACECs in land use planning. The rule emphasizes the role of ACECs in contributing to ecosystem resilience by clarifying that ACEC designation can be used to protect landscape intactness and habitat connectivity.

II. Background

A. The Need for Resilient Public Lands To Achieve Multiple Use and Sustained Yield

The BLM manages approximately 245 million acres of public lands, roughly one-tenth of the land area of the United States. These lands have become increasingly degraded in recent decades through the appearance of invasive species, extreme wildfire events, prolonged drought, and increased habitat fragmentation.[3] Degradation of the health of public lands threatens the BLM's ability to manage public lands as directed by FLPMA.

FLPMA requires that unless ''public land has been dedicated to specific uses according to any other provisions of law,'' the Secretary, through the BLM, must ''manage the public lands under principles of multiple use and sustained yield, in accordance with the land use plans developed by [the Secretary] under section 202 of this Act when they are available'' (43 U.S.C. 1732(a)). The term ''sustained yield'' means ''the achievement and maintenance in perpetuity of a high-level annual or regular periodic output of the various renewable resources of the public lands consistent with multiple use'' (43 U.S.C. 1702(h)).

The term ''multiple use'' means ''the management of the public lands and their various resource values so that they are utilized in the combination that will best meet the present and future needs of the American people; making the most judicious use of the land for some or all of these resources or related services over areas large enough to provide sufficient latitude for periodic adjustments in use to conform to changing needs and conditions; the use of some land for less than all of the resources; a combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values; and harmonious and coordinated management of the various resources without permanent impairment of the productivity of the land and the quality of the environment with consideration being given to the relative values of the resources and not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output.'' (43 U.S.C. 1702(c)).

FLPMA also directs the BLM to ''take any action necessary to prevent unnecessary or undue degradation of the lands.'' (43 U.S.C. 1732(b)). Additionally, section 102(a)(8) of FLPMA declares that it is the policy of the United States that ''the public lands be managed in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archeological values; that, where appropriate, will preserve and protect certain public lands in their natural condition; that will provide food and habitat for fish and wildlife and domestic animals; and that will provide for outdoor recreation and human occupancy and use'' (43 U.S.C. 1701(a)(8)). Many of these resources and values that FLPMA authorizes the BLM to safeguard emanate from functioning and productive native ecosystems that supply food, water, habitat, and other ecological necessities.

Taken together, FLPMA's mandate to manage public lands for multiple use and sustained yield and its requirement to protect certain resources and values requires balanced management that maintains the availability of such resources and values for future generations. (See 43 U.S.C. 1702(c)) Widespread degradation of land health significantly limits the ability of public lands and their ecosystems to provide such resources and values and is inconsistent with the management direction and responsibility conferred to the BLM through FLPMA. The general resilience of public lands will determine the BLM's ability to effectively manage for multiple use and sustained yield over the long term. Resilience is a critical ecosystem trait that allows ecosystems to maintain or regain their composition, structure, and function following disturbances, including those resulting from changing environmental conditions. For example, maintaining habitat connectivity allows organisms to adapt to a changing climate from the North Slope of Alaska to the Rio Grande Valley of Colorado and New Mexico. To ensure the resilience of public lands,

[3] See, *e.g.,* Long-Term Trends in Vegetation on Bureau of Land Management Rangelands in the Western United States (*https://www.sciencedirect.com/science/article/pii/S1550742422001075*); Greater Sage-grouse Plan Implementation: Range-wide Monitoring Report 2015–2020 (*https://eplanning.blm.gov/public_projects/2016719/200502020/20050224/250056407/Greater%20Sage-Grouse%20Five-year%20Monitoring%20Report%202020.pdf*).

FLPMA provides the BLM with ample authority and direction to conserve ecosystems and other resources and values across the public lands.

The BLM recognizes this need for public lands to continue to provide resources and values when declaring its mission ''to sustain the health, diversity, and productivity of public lands for the use and enjoyment of present and future generations.'' (*blm.gov;* see also 43 U.S.C. 1702(c)) Without ensuring that public lands and their component ecosystems can maintain their function and be resilient to future change, the agency risks failing on its statutory mandate and its commitment to future generations.

To assist the BLM in carrying out its mission and statutory mandate, this rule provides direction and tools to protect and restore landscapes and ecosystems and make decisions supported by science and data, assisting the agency in managing for resilient landscapes that support multiple uses and sustained yield of resources and preventing unnecessary or undue degradation of the lands and their resources. As intact landscapes play a central role in maintaining the resilience of an ecosystem, the rule emphasizes protecting those public lands with intact, functioning landscapes and restoring others. This rule is designed to support sustained yield such that the nation's public lands can continue to supply food, water, habitat, and other ecological necessities that can resist and recover from drought, wildfire, and other disturbances, and continue to provide energy, forage, timber, recreational opportunities, and safe and reliable access to minerals.

B. Conservation Use for Resilient Public Lands

Conservation is a key strategy for supporting resilient public lands, now and into the future. Conservation takes many forms on public lands, including in the ways grazing, recreation, forestry, wildlife and fisheries management, and many other uses are carried out. Conservation is both a land use and also an investment in the landscape intended to increase the yield of certain other benefits elsewhere or later in time. This rule focuses on conservation as a land use within the multiple use framework, including in decision-making, authorization, and planning processes. The rule develops the toolbox for conservation use—defined here as encompassing both protection and restoration actions—enabling some of the many conservation strategies the agency employs to steward the public lands for multiple use and sustained yield.

FLPMA has always encompassed conservation as a land use. As described above, FLPMA authorizes and obligates the BLM to, within the multiple use framework, protect natural resources, preserve public lands, and provide habitat for fish and wildlife, among other conservation measures. The BLM has been practicing conservation of the public lands throughout the agency's history. The change this rule aims to achieve is providing clear, consistent, and informed direction, vetted and shaped by public input, for conservation use to be implemented on the public lands in support of ecosystem resilience.

The rule does not prioritize conservation above other multiple uses. It also does not preclude other uses where conservation use is occurring. Many uses are compatible with different types of conservation use, such as sustainable recreation, grazing, and habitat management. The rule also does not enable conservation use to occur in places where an existing, authorized, and incompatible use is occurring.

One of the primary tools for conservation use that is established in this rule is restoration and mitigation leasing (called conservation leasing in the proposed rule). Restoration or mitigation leases can help facilitate dynamic landscape management over time by allowing an area to recover and be available for other uses after the termination of the lease. For example, a restoration lessee may collaborate with an existing grazing permittee to restore degraded rangeland with the ultimate goal of resuming sustainable grazing. These leases are not the only way to conduct restoration and mitigation on the public lands; these types of conservation activities occur in many ways. The leases provide a clear and consistent tool for those actions when appropriate and useful. Like all conservation uses included in the rule, restoration and mitigation leases will not be used where existing rights and authorized uses are in place that would conflict with the conservation use.

The BLM has, over the years, developed and revised regulations for many multiple uses, whereas a placeholder has remained in Title 43 of the CFR for the agency to develop regulations broadly pertaining to conservation. With this rule, the BLM provides necessary regulations for using conservation to support ecosystem resilience and landscape health.

C. Management Decisions To Build Resilient Public Lands

The rule recognizes that the BLM has three primary ways of applying conservation actions to manage for resilient public lands that inform one another and potentially overlap: (1) protection of intact, functioning landscapes; (2) restoration of degraded habitats and ecosystems; and (3) making decisions informed by appropriate conservation considerations identified through the development and execution of plans, programs, and permits. The organization of the rule text emanates from this structure, with principal sections on (1) protection of landscape intactness and guidance on the identification and designation of ACECs; (2) direction to plan for and restore degraded habitats; and (3) instruction for management actions to facilitate conservation, including application of mitigation, all based on the use of high-quality information and adherence to land health standards for all BLM programs.

1. Protection

As intact landscapes play a central role in maintaining the resilience of ecosystems, the rule provides direction for the protection of intact, functioning landscapes. The final rule directs the BLM to maintain an inventory of landscape intactness as a resource value and identify intact landscapes in land use plans and to protect the intactness of certain landscapes by, for example, implementing conservation actions that maintain ecosystem resilience and conserving landscape intactness when managing compatible uses. Inventories of landscape intactness focus on an estimate of naturalness measured against human-caused disturbance and influence. The BLM intends to assess intactness through use of watershed condition assessments consistent with peer-reviewed methods developed jointly with the U.S. Geological Survey.[4] One of the principal administrative tools the BLM has available to protect public land resources is the designation of ACECs. ACECs are areas where special management attention is needed to protect important historical, cultural, and scenic values or fish and wildlife or other natural resources; ACECs can also be designated to protect human life and safety from natural hazards. The rule clarifies and expands existing ACEC regulations to better support the BLM in carrying out FLPMA's direction to give

[4] See, for instance, this collaborative effort between the BLM and the USGS: A Multiscale Index of Landscape Intactness for the Western U.S. | U.S. Geological Survey (*usgs.gov*).

priority to the designation and protection of these important areas.

Pursuant to Executive Order 14072, *Strengthening the Nation's Forests, Communities, and Local Economies,* 87 FR 24851 (Apr. 22, 2022), and consistent with managing for multiple use and sustained yield and other applicable law, the BLM is working to ensure that forests and woodlands on public lands, including old and mature forests and woodlands, are managed to: promote their continued health and resilience, retain and enhance carbon storage, recruit old-growth forests and characteristics, conserve biodiversity, mitigate the risk of wildfires, enhance climate resilience, enable subsistence and cultural uses, provide outdoor recreation opportunities, and promote sustainable local economic development. Older forests and woodlands, including pinyon and juniper woodlands, which are the BLM's most abundant old forest type, have characteristics that contribute to ecosystem resilience and further the objectives of this rule. The characteristics include providing important wildlife habitat, maintaining intact landscapes, contributing ecosystem services, and harboring significant social and cultural values for human communities. As such, these resources will be considered and evaluated for protection and expansion under multiple provisions of the rule.

2. Restoration

To promote consistency in its application, the final rule establishes principles for the design and implementation of BLM restoration actions on public lands. To direct restoration efforts, the rule also requires that resource management plans identify restoration outcomes and that the BLM identify priority landscapes for restoration, develop restoration plans, and track implementation of restoration actions.

The rule offers new tools in the form of restoration leases and mitigation leases that allow qualified entities to directly support efforts to build and maintain resilient public lands. These leases will be available to entities seeking to restore public lands or mitigate reasonably foreseeable impacts from an authorized activity. Leases will not override valid existing rights or preclude other, subsequent authorizations so long as those authorizations are compatible with the restoration or mitigation use. The rule establishes the process for applying for and granting leases, terminating or suspending them, determining noncompliance, and setting bonding obligations. The rule expresses a preference for lease applications that are derived from collaboration with existing permittees, lease holders, or adjacent land managers or owners, or that include other specific factors enumerated in 6102.4(d) that will make lease issuance more likely. Restoration and mitigation leases will be issued for a term consistent with the time required to achieve their objectives. Restoration leases will be issued for a maximum of 10 years but can be renewed if necessary to serve the purposes for which the lease was first issued. Once these purposes have been achieved, the lease will not warrant renewal. Any mitigation lease will require a term commensurate with the impact(s) it is offsetting. Restoration and mitigation leases may also provide opportunities for co-stewardship with federally recognized Tribes.

3. Management Actions for Decision-Making

The final rule delineates how its goals can be achieved when implementing programs, establishing land use plans, and authorizing use. In doing so, the rule requires the BLM to use high-quality information, including Indigenous Knowledge. To ensure the BLM does not limit its ability to build resilient public lands when authorizing use, the rule requires the BLM to apply a mitigation hierarchy (*i.e.,* take actions to avoid, minimize, and compensate for certain residual impacts, generally in that order). (See § 6102.5.1(a)).[5] For important, scarce, or sensitive resources, the BLM must apply the mitigation hierarchy with particular care, with the goal of eliminating, reducing, and/or offsetting impact on the resource. The rule also establishes regulations to govern the BLM's approval of a third-party mitigation fund holder.

The final rule highlights the importance of environmental justice in decision-making, including advancing environmental justice through restoration and mitigation actions as one of the rule's objectives. The BLM is implementing Executive Order 14008 on *Tackling the Climate Crisis at Home and Abroad,* 86 FR 7619 (Jan. 27, 2021) and Executive Order 14096 on *Revitalizing Our Nation's Commitment to Environmental Justice for All,* 88 FR 25251 (Apr. 26, 2023), which establish environmental justice initiatives and policy goals.[6] The BLM issued guidance in September 2022 clarifying minimum requirements for incorporating environmental justice considerations in environmental reviews (Instruction Memorandum 2022–059, ''Environmental Justice Implementation''). This rule builds on the agency's current commitments and direction by highlighting opportunities to address impacts to disadvantaged communities that are marginalized by underinvestment and overburdened by pollution and to advance environmental justice. In planning for and prioritizing landscapes for restoration, the rule requires consideration of where restoration can address impacts on communities' environmental justice concerns, as well as other social and economic benefits. Environmental justice considerations are also identified as a factor in evaluating proposals for restoration and mitigation lease applications.

To support conservation actions and decision-making, the rule extends the application of the fundamentals of land health (taken verbatim from the existing fundamentals of rangeland health at 43 CFR 4180.1 (2005)) and related standards and guidelines to all lands managed by the BLM and across all program areas. The fundamentals are general descriptions of conditions that maintain the health and functionality of watersheds, ecological processes, water quality, and threatened, endangered, and special-status species habitat. The standards measure the level of physical and biological conditions required for healthy lands and sustainable uses of public lands, essentially identifying trends toward achieving or not achieving desired conditions. Assessment and evaluation of the standards informs decision-making at all levels of the BLM, including decisions made in resource management plans. However, it is the evaluation of multiple lines of evidence to conclude whether or not each land health standard is being achieved that is most relevant to a decision maker. Multiple lines of evidence that may be used to evaluate land health include, but are not limited to, standardized quantitative monitoring data, remote sensing-derived maps and data, qualitative assessments, photos, water quality data, habitat assessments, disturbance and land use

[5] The BLM's final rule adopts the definition of ''mitigation'' used by the Council on Environmental Quality's regulations implementing the procedural requirements of NEPA, 40 CFR 1508.1(s), including for compensatory mitigation: ''Compensating for the effect by replacing or providing substitute resources or environments.'' *Id.* § 1508.1(s)(5). This definition also aligns with existing BLM policy, including its Mitigation Manual Section, MS–1794, and its Mitigation Handbook, H–1794–1.

[6] These efforts build on prior Executive Orders, such as Executive Order 12898 on *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,* 59 FR 7629 (Feb. 11, 1994).

history, and weather and climate data relevant to each land health standard. Determining if a standard is being achieved, or not achieved, can inform how a land use may be modified or adapted to improve land health conditions consistent with the fundamentals. The rule does not require, however, that individual actions ''comply'' with the fundamentals of land health, nor does it require achievement of those fundamentals (as measured by the land health standards) as a precondition for any BLM decision.

Currently, the fundamentals of land health and related standards apply only to rangeland systems where the BLM authorizes grazing.[7] Existing land health standards vary across regions and states creating a complex, but locally adapted system of rangeland evaluation. The rule includes a process for developing and adopting consistent national land health standards and amending or supplementing them to apply them more effectively to habitats managed by the BLM other than rangelands (*e.g.,* forests, deserts, shrublands, wetlands). Until the BLM has developed a consistent set of national standards, existing standards and indicators will be applied according to the process described within this rule. However, broadening the applicability of existing land health standards ensures the BLM will more formally and consistently consider the condition of public lands in decision-making. The rule includes instruction, largely consistent with the existing framework at 43 CFR 4180.1, on how the BLM must assess, evaluate, and determine if public lands are meeting land health standards. At a critical moment in the health and history of our public lands, the rule directs the BLM to perform such assessments and evaluations at broad spatial and temporal scales, thereby creating efficiencies in the land health process and opportunities to streamline permit renewals and authorizations.

D. Tribal Engagement and Co-Stewardship

The final rule reflects the U.S. Government's special relationship with Indian Tribes by incorporating updated requirements for government-to-government consultation, provisions for respecting Indigenous Knowledge, and direction to seek opportunities for Tribal co-stewardship.

The BLM is committed to working with Tribes in the management of the public lands, which are the ancestral homelands of many American Indian and Alaska Native Tribes. The BLM is the country's largest land manager, and it is vital that the BLM respect the nation-to-nation relationship that exists with American Indian and Alaska Native Tribes while incorporating co-stewardship where possible. Engaging with Tribes through co-stewardship opportunities is a priority for the BLM as identified in: Joint Secretarial Order 3403 on *Fulfilling the Trust Responsibility to Indian Tribes in the Stewardship of Federal Lands and Waters* (Nov. 15, 2021); BLM Permanent Instruction Memorandum No. 2022–011, *Co-Stewardship with Federally Recognized Indian and Alaska Native Tribes Pursuant to Secretary's Order 3403* (Sept. 13, 2022); and the Department of the Interior Departmental Manual Part 502, *Collaborative and Cooperative Stewardship with Tribes and the Native Hawaiian Community.*

In response to comments and consultation on the proposed rule,[8] the BLM made several updates to the final rule to better embrace its commitment to working with Tribes in managing the public lands for ecosystem resilience and landscape health. A stated objective of the final rule (43 CFR 6101.2(i)) is to: ''[i]mprove engagement and co-stewardship of public lands with Tribal entities and promote the use of Indigenous Knowledge in decision-making.'' The final rule intends to achieve this objective through provisions for Tribal consultation, incorporation of Indigenous Knowledge, and co-stewardship.

The final rule directs the BLM to meaningfully consult with Indian Tribes and Alaska Native Corporations on actions that are determined, after allowing for Tribal input, to potentially have a substantial effect on the Tribe or Corporation. In taking management actions for ecosystem resilience, and in recognition that Tribes can initiate consultation upon request, the final rule requires the BLM to meaningfully consult with Indian Tribes and Alaska Native Corporations during the decision-making process. These changes promote consistency with Departmental Manual guidance for consultation with Tribes.

The rule includes guidance for respecting and considering Indigenous Knowledge and directs the BLM to identify opportunities for co-stewardship as an overarching objective and specifically when managing intact landscapes, planning restoration actions on public lands, and taking management actions for ecosystem resilience.

The final rule also includes updated definitions for Indigenous Knowledge and high-quality information to reflect current guidance and to make clear that Indigenous Knowledge qualifies as high-quality information when it is gained by prior informed consent, free of coercion, and generally meets the standards for high-quality information.

E. Inventory, Evaluation, Designation, and Management of ACECs

To implement FLPMA's direction to ''give priority to the designation and protection of areas of critical environmental concern,'' (43 U.S.C. 1712(c)(3)), the rule updates regulatory requirements found at 43 CFR 1610.7–2 and codifies policy instruction found in the BLM Manual that guides its treatment of ACECs. (*https://www.ntc.blm.gov/krc/system/files?file=legacy/uploads/5657/5_1613_ACEC_Manual%201988.pdf*) The BLM inventories, evaluates, and designates ACECs as part of the land use planning process. The land use planning process guides BLM resource management decisions in a manner that allows the BLM to respond to issues and consider trade-offs among environmental, social, and economic values in determining appropriate land uses for specific areas. Further, the planning process requires coordination, cooperation, and consultation and provides other opportunities for public involvement that can foster relationships, build trust, and result in durable decision-making.

In 40 years of applying the procedures found at 43 CFR 1610.7–2 and in the ACEC Manual, the BLM has identified a need for several revisions that it has now made in this final rule. These revisions are needed to provide clear direction and comprehensive guidance encompassing all elements of the ACEC designation and management process.

[7] The BLM currently maintains inventory, assessment and monitoring data from its implementation of the grazing regulations related to rangeland health through the agency's Assessment, Inventory, and Monitoring (AIM) program, and makes this data available to the public. *https://www.blm.gov/aim.*

[8] Pueblo of Tesque Comments on Bureau of Land Management Conservation and Landscape Health Rule (July 5, 2023), ; Pyramid Lake Paiute Tribe, Public Comment Regarding the Proposed Public Lands Rule (June 27, 2023), *https://www.regulations.gov/comment/BLM-2023-0001-153233;* Northwest Arctic Native Association (NANA) Regional Corporation, Inc., Comments—Proposed Conservation and Landscape Health Rule (July 5, 2023), *https://www.regulations.gov/comment/BLM-2023-0001-154147;* Colorado River Indian Tribes, Comments on BLM Proposed Federal Land Policy and Management Act of 1979 (FLPMA) Regulations on Conservation and Landscape Health (June 20, 2023), *https://www.regulations.gov/comment/BLM-2023-0001-120501;* Ute Indian Tribe of the Uintah and Ouray Reservation, Comments on the Bureau of Land Management Proposed Rule on Conservation and Landscape Health (June 27, 2023), *https://www.regulations.gov/comment/BLM-2023-0001-147694.*

Additionally, the final rule codifies the BLM's procedures for considering and designating potential ACECs, providing more cohesive direction and consistency than the previous procedures, which were described partially in regulation and partially in agency policy. The rule maintains the general process for inventorying, evaluating, designating, and managing ACECs, but makes specific changes to clarify and improve that process. The process is generally described here, with more detailed explanation in the ''Section-by-Section Discussion of the Final Rule and Revisions from the Proposed Rule'' and in the ''Response to Public Comments'' sections of this preamble to the final rule.

In the initial stages of the land use planning process, the BLM, through inventories and external nominations, identifies any potential new ACECs to evaluate for relevance, importance, and the need for special management attention. The BLM determines whether such special management attention is needed by evaluating land use planning alternatives and considering additional issues related to the management of the proposed ACEC, including public comments received during the planning process. Special management measures may also provide an opportunity for Tribal co-stewardship. In approved resource management plans, the BLM identifies all designated ACECs and provides the management direction necessary to protect the relevant and important values for which the ACECs were designated.

This rule establishes procedures that require the BLM to consider ecosystem resilience, landscape-level needs, and rapidly changing landscape conditions in designating and managing ACECs, and it establishes a management standard to ensure ACEC values are appropriately conserved. The rule also provides that the BLM may, at the agency's discretion, implement temporary management for potential ACECs identified outside of an ongoing planning process until the potential ACEC can be evaluated for designation through a land use planning process. When implementing temporary management, the BLM will comply with all applicable laws, including the National Environmental Policy Act (NEPA), notify the public of the temporary management, and periodically reevaluate its decision to provide for temporary management. These provisions do not change the presumption that the BLM generally addresses its management of areas that may be appropriate for an ACEC designation through the land use planning process. The final rule also codifies research natural areas as a type of ACEC designated for the primary purpose of research and education on public lands, consistent with existing regulations (43 CFR subpart 8223) and policy.

The BLM intends to revise its ACEC manual to integrate the new and existing regulations into policy and provide more detailed guidance for their implementation. Guidance will help the BLM and the public better understand how the ACEC regulations are applied on a case-by-case basis.

F. Statutory Authority

FLPMA establishes the BLM's mission to manage public lands ''under principles of multiple use and sustained yield'' (except for lands where another law directs otherwise). (43 U.S.C. 1732(a)) Multiple use is defined as:

> the management of the public lands and their various resource values so that they are utilized in the combination that will best meet the present and future needs of the American people; making the most judicious use of the land for some or all of these resources or related services over areas large enough to provide sufficient latitude for periodic adjustments in use to conform to changing needs and conditions; the use of some land for less than all of the resources; a combination of balanced and diverse resource uses that takes into account the long- term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values; and harmonious and coordinated management of the various resources without permanent impairment of the productivity of the land and the quality of the environment with consideration being given to the relative values of the resources and not necessarily to the combination of uses that will give the greatest economic return or the greatest unit output.

(43 U.S.C. 1702(c)). Sustained yield is defined as, ''the achievement and maintenance in perpetuity of a high-level annual or regular periodic output of the various renewable resources of the public lands consistent with multiple use.'' (43 U.S.C. 1702(h)).

FLPMA also authorizes the Secretary to promulgate implementing regulations necessary ''to carry out the purposes'' of the Act. (43 U.S.C. 1740) This rule, enacted under that authority, (1) defines and regulates conservation use on the public lands in service of FLPMA's multiple use and sustained yield mandates; (2) provides for third-party authorizations to use the public lands for restoration and mitigation under FLPMA section 302(b) (43 U.S.C. 1732(b)); and (3) revises the existing regulations implementing FLPMA's direction in sections 201(a) and 202(c)(3) (43 U.S.C. 1711(a) and 1712(c)(3)) that the BLM shall give priority to the designation and protection of ACECs. (*See also* 43 U.S.C. 1701(a)(11) (''[I]t is the policy of the United States that—regulations and plans for the protection of public land areas of critical environmental concern be promptly developed.'')).

This rule clarifies that conservation is a use on par with other uses and responds to the direction inherent in FLPMA's multiple use and sustained yield mandate to manage public lands for resilience and future productivity and to mitigate resource impacts. A number of comments questioned the BLM's authority to treat ''conservation'' as a use within FLPMA's multiple use framework. As a general matter, the definition of ''multiple use'' makes clear, and courts have affirmed, that managing some lands for conservation use is a permissible, and indeed crucial, aspect of managing public lands under the principles of multiple use and sustained yield, as FLPMA requires. (*See* 43 U.S.C. 1702(c); *see also New Mexico ex rel. Richardson* v. *BLM,* 565 F.3d 683, 710 (10th Cir. 2009) (''It is past doubt that the principle of multiple use does not require BLM to prioritize development over other uses . . . BLM's obligation to manage for multiple use does not mean that development must be allowed . . . Development is a possible use, which BLM must weigh against other possible uses—including conservation to protect environmental values.''); *Theodore Roosevelt Conservation P'ship* v. *Salazar,* 616 F.3d 497, 518 (D.C. Cir. 2010) (''[T]he Bureau has wide discretion to determine how those [FLPMA] principles [of multiple use and sustained yield] should be applied.''); *Or. Nat. Desert Ass'n* v. *BLM,* 531 F.3d 1114, 1134 (9th Cir. 2008) (recognizing that the BLM's ''wide authority to manage the public lands under principles of multiple use and sustained yield allows it ample discretion for management of lands with wilderness values'')).

Public Comments on Statutory Authority

Several comments suggested more specifically that the decision in *Public Lands Council* v. *Babbitt,* 167 F.3d 1287 (10th Cir. 1999), would prohibit the restoration and mitigation leases available under this rule.

We disagree. In that case, the Tenth Circuit held that the Taylor Grazing Act and section 402 of FLPMA could not authorize ''issuing a 'grazing permit' that excludes livestock grazing for the entire term of the permit.'' *Id.* at 1307.

The court, therefore, enjoined the regulations purporting to authorize Taylor Grazing Act permits that provided for no grazing. In doing so, the Tenth Circuit expressly stated that the question in the case was ''not whether the Secretary possesses general authority to take conservation measures—which clearly he does.'' *Id.*

The present rule, in contrast to the grazing rule at issue in *Public Lands Council* v. *Babbitt,* is an exercise of that authority to take conservation measures. It does not rely on the Taylor Grazing Act, nor does it modify the terms and conditions available for grazing permits or authorize the BLM to issue grazing permits approving non-grazing uses. Rather, this rule provides for a separate category of leases, which can be exercised on public lands in areas with other ongoing uses, such as active grazing, consistent with the BLM's authority under FLPMA to ''manage the public lands under principles of multiple use and sustained yield'' (43 U.S.C. 1732(a)) and to ''regulate, through easements, permits, leases, licenses, published rules, or other instruments as the Secretary deems appropriate, the use, occupancy, and development of the public lands.'' (43 U.S.C. 1732(b)) The final rule renames what the proposed rule called ''conservation leases'' as ''restoration leases'' and ''mitigation leases'' to more precisely describe the activities that would be authorized on the leased lands.

A number of comments that object to including ''conservation'' alongside other uses in FLPMA's multiple use framework, including a letter from the Small Business Administration, Office of Advocacy (Advocacy), point to the absence of the word ''conservation'' from FLPMA's definition of ''principal or major uses.'' (*See* 43 U.S.C. 1702(*l*))

We disagree. Those comments misapprehend the meaning of the term ''principal or major uses'' within the statutory framework established by FLPMA. That term does not appear in any of FLPMA's discussion of multiple use, and the principal or major uses included in the definition of that term do not hold an exclusive or even superior position within the multiple use framework. Indeed, that defined term appears in FLPMA only in section 202(e) (43 U.S.C. 1712(e)), which provides that all land use plan decisions are subject to revision and modification and—specific to principal or major uses—includes a Congressional reporting provision (section 202(e)(2)) that contains no substantive constraint on the BLM's authority. The Advocacy letter asserts that restoration or mitigation leases must be submitted to Congress, citing Section 202(e)(2). But section 202(e)(2) merely provides for congressional *notification* if a management decision ''excludes (that is, totally eliminates)'' one or more of the principal or major uses for two or more years on an area exceeding one hundred thousand acres or more'' of the public lands. (43 U.S.C. 1712(e)(2)) The adoption of the final rule does not immediately result in any restoration or mitigation lease going into effect, much less one that covers one hundred thousand or more acres, let alone one that ''totally eliminates'' a principal or major use on such an area for two or more years. Nor does it follow from the rule that the leases the BLM does issue would necessarily meet the criteria to trigger section 202(e)(2). More importantly, the Advocacy letter fails to grapple with the necessary and obvious implication of this provision: Congress's clear recognition that the BLM is *authorized* to take actions that would exclude principal or major uses—including from large tracts of land—as long as it reports such actions to Congress when it does. In short, the provision is not only inapplicable to most, if not all, restoration and mitigation leases that may be issued under this rule, but it clearly demonstrates that the BLM has the authority Advocacy claims it lacks.

Several commenters suggested that the issuance of a final rule that recognizes conservation as a use of the public lands and allows for the issuance of restoration and mitigation leases might be challenged in federal court under the Administrative Procedure Act, speculating further that a reviewing court might evaluate these features of the rulemaking under the major questions doctrine.

We disagree. The Supreme Court deemed the major questions doctrine to apply when an agency's asserted statutory authority is unclear and when the ''history and the breadth of the authority'' and the ''economic and political significance'' of its assertion provide a ''reason to hesitate.'' *West Virginia* v. *EPA,* 142 S. Ct. 2587, 2595 (2022). But as this preamble to this final rule explains elsewhere in detail, and as courts have confirmed, FLPMA's animating principles of multiple use and sustained yield embrace conservation use as an integral component of the BLM's stewardship of the public lands. Moreover, while restoration and mitigation leases are specific new tools for managing the public lands, FLPMA provides clear and broad authority to manage the public lands at the discretion of the Secretary, including for conservation use, for the reasons described in detail above, and including through leases. (43 U.S.C. 1732(a)–(b))

The BLM has a long history of exercising that broad regulatory authority to manage its lands through leases and similar instruments, including by issuing permits or right-of-way grants that authorize the permit holder to implement restoration and mitigation as a component or a condition of an authorization to use the public lands for development or extractive purposes. See, *e.g.,* M–37039, The Bureau of Land Management's Authority to Address Impacts of its Land Use Authorizations through Mitigation, at 11–22 (Dec. 21, 2016) (reinstated by M–37075 (Apr. 15, 2022)) (''[The] BLM's charge under FLPMA to manage public lands based on principles of multiple use and sustained yield supports use of mitigation. The authority to evaluate and impose mitigation arises out of the broad authority FLPMA vests in the BLM to pursue congressional goals . . . for public lands. The BLM can evaluate and require mitigation through both the land use planning process and site-specific authorizations.''); *Theodore Roosevelt Conservation P'ship,* 616 F.3d at 505–06, 515–17 (concerning planning decision that outlined mitigation measures to be imposed as conditions of approval for oil and gas drilling). For the reasons noted above, Congress has spoken clearly that conservation—including in the forms of restoration or mitigation—is an appropriate use of the public lands and that, where a given use of the public lands is appropriate, leasing is an appropriate means to regulate such use.

Several commenters noted that a different BLM rule—Resource Management Planning, 81 FR 89580 (Dec. 12, 2016)—was subject to a congressional joint resolution of disapproval under the Congressional Review Act (CRA) (5 U.S.C. 802). These commenters suggested that this rule, therefore, may be precluded by the CRA provision that ''a new rule that is substantially the same as'' a rule that does not continue in effect due to a joint resolution of disapproval may not be issued. (5 U.S.C. 801(b)(2))

We disagree. This rule, which would promulgate a series of new regulations at 43 CFR part 6100 and make changes to 43 CFR 1610.7–2, is not substantially the same as the BLM's 2016 rule. The 2016 rule included amendments to § 1610.7–2, but they were different in substance and form from the revisions proposed in this rule and involved a much broader amendment to all of the

planning regulations at 43 CFR part 1600. For example, this rule identifies ''landscape intactness'' as a value meriting consideration for conservation, including through designation of ACECs, and calls for land health evaluations at geographic scales broader than grazing allotments. But these features of the present rule do not amount to the same landscape-scale planning approach that was central to the 2016 rule, and which would have been (and would need to be) implemented through a wholesale revision of the planning regulations at 43 CFR part 1600.

A number of comments noted that the BLM's management of the public lands is subject to additional laws beyond FLPMA and in some cases asked that the BLM limit the geographic scope of the final rule to exclude areas of public lands where another statute provides direction or informs how the BLM should manage those lands.

We agree that laws beyond FLPMA govern BLM's management of the public lands, but we decline to amend the rule in response to these comments. The final rule applies across BLM-managed lands. However, implementation of the rule—that is, land use planning and individual project-level decisions—will be subject to and must be undertaken consistent with all applicable laws, including the Mining Law of 1872, 30 U.S.C. 22 *et seq.,* the Oregon and California Revested Lands Sustained Yield Management Act of 1937, 43 U.S.C. 2601 *et seq.* (the O&C Act), the Alaska National Interest Lands Conservation Act, 16 U.S.C. 3101 *et seq.* (ANILCA), the Paleontological Resources Preservation Act of 2009, 16 U.S.C. 470aaa *et seq.* (PRPA), the Endangered Species Act, 16 U.S.C. 1531 *et seq.* (ESA), the National Environmental Policy Act, 42 U.S.C. 4321 *et seq.* (NEPA), and the National Historic Preservation Act, 54 U.S.C. 300101 *et seq.* (NHPA).

G. Related Executive and Secretarial Direction

The rule is consistent with directives set forth in several Executive and Secretary's Orders and related policies and strategies. These directives call on the Department of the Interior (DOI), and the Federal Government more generally, to use landscape-scale, science-based, collaborative approaches to natural resource management.

They include Executive Order 14072, *Strengthening the Nation's Forests, Communities, and Local Economies,* recognizes that healthy forests are ''critical to the health, prosperity, and resilience of our communities.'' It states a policy to:

> pursue science-based, sustainable forest and land management; conserve America's mature and old-growth forests on Federal lands; invest in forest health and restoration; support indigenous traditional ecological knowledge and cultural and subsistence practices; honor Tribal treaty rights; and deploy climate-smart forestry practices and other nature-based solutions to improve the resilience of our lands, waters, wildlife, and communities in the face of increasing disturbances and chronic stress arising from climate impacts.

The Executive Order calls for defining, identifying, and inventorying our nation's old and mature forests, then stewarding them for future generations to provide clean air and water, sustain plant and animal life, and respect their special importance to Tribal Nations. This rule advances these objectives by providing a framework for conservation use on public lands that would apply to mature and old-growth forests and woodlands managed by the BLM.

And Joint Secretarial Order 3403 on *Fulfilling the Trust Responsibility to Indian Tribes in the Stewardship of Federal Lands and Waters,* issued on November 15, 2021, by DOI and the Department of Agriculture, reiterates the Departments' commitment to the United States' trust and treaty obligations as an integral part of managing Federal lands. The order emphasizes that ''Tribal consultation and collaboration must be implemented as components of, or in addition to, Federal land management priorities and direction for recreation, range, timber, energy production, and other uses, and conservation of wilderness, refuges, watersheds, wildlife habitat, and other values.'' The order also notes the benefit of incorporating Tribal expertise and Indigenous Knowledge into Federal land and resources management.

H. Public Involvement in the Proposed Rule

The BLM published the proposed rule in the **Federal Register** on April 3, 2023 (88 FR 19583), for a 75-day comment period ending on June 20, 2023. In response to public requests for an extension, on June 15, 2023, the BLM announced a 15-day extension of the comment period. The official comment period extension notice was published on June 20, 2023 (88 FR 39818). The extended comment period closed on July 5, 2023.

During the comment period, the BLM hosted a variety of public outreach activities. The BLM held two virtual public meetings on May 15 and June 5, 2023. The BLM held three in-person meetings in Denver, Colorado (May 25, 2023); Albuquerque, New Mexico (May 30, 2023); and Reno, Nevada (June 1, 2023) to provide an overview of the proposed rule and answer questions from the public. All webinars and meetings were led by a third-party facilitator. A video recording of the May 15 virtual meeting and presentation slides in English and Spanish are available on the BLM website. The BLM also posted a reviewer guide and fact sheet, frequently asked questions on topics of interest, infographics, and other background information on the BLM website to further public understanding of the proposed rule. (*https://www.blm.gov/public-lands-rule.*)

In addition, the BLM conducted external outreach and participated in dozens of meetings to discuss the content of the proposed rule, including congressional briefings; meetings with States and State agencies; meetings with grazing, recreation, renewable energy, and other stakeholder interest groups and associations; and presentations at conferences and events. Meetings were conducted by both headquarters staff and regional staff across the country.

I. Tribal Consultation on the Proposed Rule

At the beginning of the rulemaking process, letters were sent to all federally recognized Tribes and Alaska Native Claims Settlement Act Corporations informing them of the proposed rule and inviting them to engage with the BLM to discuss their thoughts and concerns. The BLM conducted government-to-government consultation on the proposed rule as requested by Tribes.

To facilitate understanding of the proposed rule, the BLM posted all meeting materials, including a recording of the first virtual meeting, frequently asked questions, and meeting handouts, on its website to accommodate Tribal members and other members of the public who could not attend a public meeting. This final rule is informed by input received from Tribes during the public comment period. Over 20 Tribal governments, Alaska Native Corporations, and tribal entities submitted formal comments on the proposed rule. Tribal comments covered a range of topics including ACEC nomination, tribal consultation and co-stewardship, protection of cultural resources, and restoration and mitigation leasing. Responses to Tribal input are addressed in the ''Tribal Engagement and Co-Stewardship'' and ''Section-by-Section Discussion of the Final Rule and Revisions from the

Proposed Rule'' sections of this preamble to the final rule.

J. Summary of Changes

The BLM received an initial total of 216,403 comments from regulations.gov. Further analysis showed that there were public comment submissions with multiple cosigners, sometimes several thousand on one submission, which were initially counted as separate submissions but ultimately identified as a single submission with multiple signatures. Therefore, although 216,403 people voiced their opinion, the final count of comment letters came to 152,673. The comment letters on the proposed rule are available for viewing on the Federal e-rulemaking portal (*https://www.regulations.gov*) (search Docket ID: BLM–2023–0001).

The BLM has reviewed all public comments and made changes, as appropriate, to the final rule based on those comments and internal review. Those changes are described in detail in the ''Section-by-Section Discussion of the Final Rule and Revisions from the Proposed Rule'' of this preamble to the final rule. In addition, the ''Response to Public Comments'' section in this preamble to the final rule provides a summary of issues raised most frequently in public comments and the BLM's response.

III. Section-by-Section Discussion of the Final Rule and Revisions From the Proposed Rule

Note: This section of the preamble discusses newly promulgated part 6100 first before turning to the revisions to § 1610.7–2, notwithstanding that § 1610.7–2 appears first in the final rule text. Part 6100 contains the core content of this final rule, which frames the need for revision to § 1610.7–2.

43 CFR Subchapter F—Preservation and Conservation

PART 6100—ECOSYSTEM RESILIENCE

Subpart 6101—General Information

Section 6101.1—Purpose

This section describes the overall purpose for the rule. The rule is designed to facilitate healthy wildlife habitat, clean water, and ecosystem resilience so that public lands can better resist and recover from disturbances like drought and wildfire. It also aims to enhance mitigation options, establishing a regulatory framework for those seeking to use the public lands, while also ensuring that the public enjoys the benefits of mitigation measures. The rule discusses the use of protection and restoration actions, as well as tools such as land health evaluations, inventory, assessment, and monitoring.

In response to public comments, the final rule expands the purpose statement to include preventing permanent impairment or unnecessary or undue degradation of public lands, in addition to promoting the use of conservation to ensure ecosystem resilience.

Section 6101.2—Objectives

This section lists the specific objectives of the rulemaking. These objectives were discussed at length earlier in the preamble for the rule. In response to public comments, the BLM added four objectives to the original six, which are to: provide for healthy lands and waters that support sustainable outdoor recreation experiences for current and future generations; prevent permanent impairment or unnecessary or undue degradation of public lands; improve engagement and co-stewardship of public lands with Tribal entities and promote the use of Indigenous Knowledge in decision-making; and advance environmental justice through restoration and mitigation actions.

Additionally, in response to public comments, the final rule expands the objective that originally read ''Promote conservation by maintaining, protecting, and restoring ecosystem resilience and intact landscapes'' by specifically adding ''including habitat connectivity and old-growth forests.''

Section 6101.3—Authority

A number of comments identified potential additional statutory authority on which the BLM might rely in promulgating this rule. The BLM has determined the reference to statutory authority is sufficient.

A number of comments raised questions about the relationship between the rule and other laws, such as the Mining Law, the O&C Act, and ANILCA, that apply to particular areas or particular uses of the public lands. The final rule adds language in this section to clarify that implementation of the rule is subject to other applicable laws.

Section 6101.4—Definitions

This section provides new definitions for concepts such as conservation, ecosystem resilience, sustained yield, mitigation, and unnecessary or undue degradation, along with other terms used throughout the rule text. These definitions apply to the use of those terms in part 6100, while definitions for the terms casual use, conserve, ecosystem resilience, intactness, landscape, monitoring, protect, and restore also apply to the use of those terms in § 1610.7–2.

The final rule adopts, without revision, the proposed definitions of the terms: casual use; important, scarce, and sensitive resources; mitigation; mitigation strategies; monitoring; public lands; and reclamation. The final rule revises the proposed definitions of the terms: conservation, disturbance, effects, high-quality information, Indigenous Knowledge, intact landscape, landscape, permittee, protection, restoration, sustained yield, and unnecessary or undue degradation (including by identifying the elements of undue degradation and unnecessary degradation).

The final rule defines additional terms to provide further clarity for implementing the rule: in-lieu fee program, intactness, land health, mitigation bank, mitigation fund, significant causal factor, significant progress, and watershed condition assessment. The final rule removes the definitions of the terms best management practices and land enhancement. The BLM decided to remove the definition of best management practices, because it is not a term that is generally used for describing mitigation measures. The BLM decided to remove the definition of land enhancement based on public comments that found the term confusing.

The proposed rule defined the term ''resilient ecosystems.'' The final rule defines ''ecosystem resilience'' instead. The final rule does not, as some comments suggested it should, formally define the term ''permanent impairment,'' but the BLM intends that its meaning be informed by how it is used within the rule's definition of sustained yield.

The following paragraphs describe the definitions adopted in the final rule and changes to these definitions from the proposed rule as applicable.

The final rule defines the term ''casual use'' in order to clarify that the existence of a restoration or mitigation lease would not in and of itself preclude the public from accessing public lands for noncommercial activities such as recreation. Authorized officers may temporarily close public access for purposes authorized by restoration and mitigation leases, such as habitat improvement projects. However, in general, public lands leased for these purposes under the final rule would continue to be open to public use. The BLM received public comments recommending the definition be expanded to explicitly include uses

such as recreation. However, the BLM decided to retain the definition from the proposed rule because it exists in the same form in current regulations at 43 CFR 2920.0–5(k). The final rule adds language to the restoration and mitigation leasing section to clarify that leases will not preclude access to or across leased areas for recreation use, research use, or other compatible authorized uses, in addition to casual use. The definition of ''casual use'' in this part does not change the definition of casual use in 43 CFR 3809.5.

The final rule defines ''conservation'' in the context of these regulations to mean the management of natural resources to promote protection and restoration. The overarching purpose of the rule is to help facilitate the use of conservation to support ecosystem resilience, and in doing so the final rule clarifies conservation as a use within the BLM's multiple use framework, including in decision-making concerning land use planning and proposed projects. The final rule includes a stated objective to promote conservation on public lands, and subpart 6102 outlines principles, directives, management actions, and tools—including a new tool in restoration and mitigation leases—to meet this objective and fulfill the purpose of the rule. The BLM received comments recommending the definition of ''conservation'' more closely align with other definitions and recommending that the BLM distinguish between ''conservation'' and ''preservation.'' The definition of ''conservation'' was updated in the final rule to make clear that conservation is a use and that protection and restoration are tools to achieve conservation.

The final rule defines the term ''disturbance'' to provide the BLM with guidance in identifying and assessing impacts to ecosystems, restoring affected public lands, and minimizing and mitigating future impacts. Identifying and mitigating disturbances and restoring ecosystems are important components of supporting ecosystem resilience on public lands. The BLM received public comments recommending the BLM clarify that disturbances can be natural or human-caused, suggesting that defining disturbance as a discrete event was too restrictive, and recommending that the BLM adjust the definition to more closely align with how ''disturbance'' is used in environmental impact statements. The definition of disturbance was updated in the final rule to clarify that disturbance can be either discrete or chronic, characteristic (where ecosystem or species have evolved to survive such a disturbance) or uncharacteristic, and that disturbance can be natural or human-caused.

The final rule defines the term ''ecosystem resilience'' (whereas the proposed rule included a definition of ''resilient ecosystem'') in the context of the rule's foundational precept that the BLM's management of public lands on the basis of multiple use and sustained yield relies on resilient ecosystems. The definition is broad and mirrors Department guidance by including concepts of resistance, recovery, and adaptation. The BLM received comments that suggested removing this term, changing the definition to clarify that habitat connectivity is key to a resilient ecosystem, and changing the definition to better and more accurately describe the characteristics of a resilient ecosystem. The BLM changed the term to ''ecosystem resilience'' to match the usage of this term in the rule and defined ecosystem resilience to be consistent with existing DOI definitions of this term.[9] DOI's definition of ecosystem resilience is inclusive of three commonly used terms in scientific literature: resistance (*i.e.,* withstand disturbance), recovery (*i.e.,* recover from disturbance, and adaptability (*i.e.,* change/adapt to disturbance). The purpose of the rule is to facilitate the use of conservation as part of sustained yield, such that ecosystems on public lands can adapt to environmental change, resist disturbance, and maintain or regain their function following environmental stressors such as drought and wildfire.

The final rule defines the term ''effects'' as the direct, indirect, and cumulative impacts from a public land use and clarifies that the term should be viewed as synonymous with the term ''impacts'' for the purposes of the rule. The BLM received comments recommending the definition be changed to match the definition of effects in the BLM's planning regulations. The definition of effects was updated in the final rule to reference 40 CFR 1508.1(g) and clarify that the use of direct, indirect, and cumulative impacts in the rule is consistent with the definition of those terms in 40 CFR 1508.1(g).

The final rule defines the term ''high-quality information'' so that its use would ensure that the best available scientific information underpins decisions and actions that would be implemented under the proposed rule to achieve ecosystem resilience. The definition also clarifies that Indigenous Knowledge can be high-quality information that should be considered alongside other information that meets the standards for objectivity, utility, integrity, and quality set forth in the Department's Information Quality Guidelines. *https://www.doi.gov/ocio/policy-mgmt-support/information-quality-guidelines.* The BLM received public comments recommending that Indigenous Knowledge be considered as high-quality information, recommending that the BLM use the term ''credible data'' to describe high-quality information, and that the definition be clarified to be more specific about what qualifies as high-quality information. The definition of high-quality information was updated in the final rule to reference the most current Department guidance on scientific information and to specify when Indigenous Knowledge would be considered high-quality information in decision-making.

The final rule defines the terms ''important,'' ''scarce,'' and ''sensitive'' resources to provide clarity and consistency in the BLM's implementation of mitigation requirements, including under the final rule. The BLM received comments that the definition of these terms was vague and requesting more detail to clarify when a resource would qualify as important, scarce, or sensitive, as well as comments requesting more clarity on how the BLM determines whether a resource is important, scarce, or sensitive. The final rule does not change the definition of these terms, which are consistent with the BLM's mitigation policy and handbook. A determination that a resource is important, scarce, or sensitive is dependent on location, conditions within a planning area affecting a particular resource (*e.g.,* drought), and the adverse effects on that resource from other past and foreseeable future land uses.

The final rule defines the term ''Indigenous Knowledge'' to reflect the DOI's policies, responsibilities, and procedures to respect and equitably promote the inclusion of Indigenous Knowledge in the Department's decision-making, resource management, program implementation, policy development, scientific research, and other actions. The BLM received comments recommending changes to the definition of this term to encompass proper terminology for Indigenous Knowledge and make it consistent with existing Department regulations and guidance, or to drop the term from the rule. The definition of Indigenous Knowledge was updated in the final

[9] *https://www.doi.gov/sites/default/files/department-of-interior-climate-action-plan-final-signed-508-9.14.21.pdf.*

rule to clarify that Tribes may use different terms to refer to this concept and to bring the definition of Indigenous Knowledge in line with current BLM, Department, and White House guidance.[10] The final rule adds a definition for the term ''in lieu fee program.'' This term is used in § 6102.5.1, Mitigation, to describe an available method for offsetting adverse impacts. The definition of this term is consistent with the BLM's mitigation policy.

The final rule defines the term ''intact landscape'' to guide the BLM with implementing direction. The rule (§ 6102.2) would require the BLM to identify intact landscapes on public lands, manage certain landscapes to protect their intactness, and pursue strategies to protect and connect intact landscapes. The BLM received comments suggesting the definition be updated to clarify the size of an intact landscape, clarify the characteristics of an intact landscape (including cultural landscapes), and add habitat connectivity and mature, old-growth forests as markers of an intact landscape. The definition was updated in the final rule to reflect commonly used definitions in policy and ecological literature, link the definition of ''intact landscape'' to the revised ''landscape'' definition, and define intact landscapes in a manner that is more easily measured and assessed by the BLM to inform conservation actions. The revised definition reflects the reality that intactness exists on a spectrum and efforts to protect intactness should not be limited by a single threshold, but rather reflect landscape-specific levels required to support multiple use and sustained yield.

The final rule adds a definition for the term ''intactness,'' which is a measure of the degree to which human influences alter or impair the structure, function, or composition of a landscape. Because the rule requires the BLM to identify intact landscapes, the agency will need to measure and inventory intactness as a resource value. The final rule clarifies that as part of managing to protect intact landscapes, the BLM will develop and maintain an inventory of landscape intactness using watershed condition assessments to establish a consistent baseline condition. The BLM will then use the intactness inventory, along with other high-quality information including habitat connectivity and migration corridor data, to identify intact landscapes in the land use planning process and consider management opportunities.

The final rule adds a definition for the term ''land health.'' Land health is used throughout the rule to refer to the concept of a healthy and functioning ecosystem, and the BLM defines the term in the final rule to clarify the desired outcome of establishing land health standards and to be consistent with the definition of rangeland health in the BLM's Rangeland Health Standards Handbook, H–4180–1.[11]

The final rule makes small adjustments to the definition of the term ''landscape'' to be more inclusive in terms of the types of resources and interests that can anchor a landscape and to align with definitions used in landscape ecology. The term ''landscape'' is used throughout the rule to characterize a meaningful area of land and waters on which restoration, protection, and other management actions will take place. Determining how the BLM's management actions can influence the health and resilience of ecosystems can vary across landscapes and over time.

The rule defines ''mitigation'' consistent with the definition provided by existing Council on Environmental Quality regulations (40 CFR 1508.1(s)), which identify various ways to address adverse impacts to resources, including steps to avoid and minimize those impacts and compensate for residual impacts. As a tool to achieve ecosystem resilience of public lands, the BLM will generally apply a mitigation hierarchy to address impacts to public land resources, seeking to avoid, then minimize, and then compensate for any residual impacts. This definition and the related provisions in the rule supplement existing DOI policy, which among other things provides boundaries to ensure that compensatory mitigation is durable and effective. The BLM made no changes to the definition from the proposed rule.

The final rule adds a new definition for the term ''mitigation bank'' because the term is used in the final rule along with ''in-lieu fee program'' as a category of mitigation projects that would require a mitigation lease with additional requirements beyond those that would be required for smaller, single-use mitigation projects. A mitigation bank is a site where resources are restored, established, enhanced, or protected for the purpose of providing compensatory mitigation for an authorized use that is impacting similar resources elsewhere. The definition in the rule is consistent with the definition in the BLM's Mitigation Manual, MS–1794.[12]

The final rule adds a new definition for the term ''mitigation fund'' because the rule provides standards for the BLM to approve, through a formal agreement, a third-party mitigation fund holder to implement compensatory mitigation programs or projects. A mitigation fund is an account established by a mitigation fund holder to collect and then disperse funds for projects that satisfy compensatory mitigation commitments and obligations. The rule also provides for the BLM in some circumstances to require mitigation lease holders to submit a formal agreement with a qualified mitigation fund holder.

The final rule defines the term ''mitigation strategies'' as documents that identify, evaluate, and communicate potential mitigation needs and mitigation measures in advance of anticipated public land uses. The BLM received comments recommending replacing the word ''strategies'' with ''approaches'' or ''documents.'' The final rule does not change the definition of this term, which is consistent with the definition of mitigation strategies from the BLM's Mitigation Manual, MS–1794.

The rule defines the term ''monitoring'' to describe a critical suite of activities involving observation and data collection to evaluate (1) existing conditions, (2) the effects of management actions, or (3) the effectiveness of actions taken to meet management objectives. Management for ecosystem resilience requires the BLM to understand how proposed use activities impact resource condition at many scales. Monitoring is a critical component of the BLM's Assessment, Inventory and Monitoring (AIM) Strategy,[13] which provides a standardized framework for assessing natural resource condition and trends

[10] Executive Office of the President, Office of Science and Technology Policy and Council on Environmental Quality, Guidance for Federal Departments and Agencies on Indigenous Knowledge (Nov. 30, 2022), *https://www.whitehouse.gov/wp-content/uploads/2022/12/OSTP-CEQ-IK-Guidance.pdf;* BLM Instruction Memorandum No. 2022–011, Co-Stewardship with Federally Recognized Indian and Alaska Native Tribes Pursuant to Secretary's Order 3403 (Sept. 13, 2022), *https://www.blm.gov/policy/pim-2022-011.*

[11] This handbook describes the authorities, objectives, and policies that guide assessment of public land health and taking appropriate action to achieve, or make progress toward achieving, specified rangeland health standards. *https://www.blm.gov/sites/blm.gov/files/uploads/Media_Library_BLM_Policy_h4180-1.pdf.*

[12] This manual provides guidance on implementing consistent principles and procedures for mitigation in the BLM's authorization of public land uses. *https://www.blm.gov/sites/default/files/docs/2021-11/MS-1794%20Rel.%201-1807.pdf.*

[13] The *AIM Strategy* provides quantitative data and tools to guide and justify policy actions, land uses, and adaptive management decisions. *https://www.blm.gov/aim.*

on BLM-administered public lands. The BLM did not change the definition of ''monitoring'' from the proposed rule because it is based on the definition and use of that term in the grazing regulations (43 CFR 4100.0–5), is science-based, and enables the application of data to inform land management and understand management effects.

The rule defines the term ''permittee'' as a person or organization with a valid permit, right-of-way grant, lease, or other land use authorization from the BLM. The rule largely discusses ''permittees'' when identifying the responsibility of parties in the context of mitigation and in discussing the opportunities to rely on third parties in complying with mitigation requirements. The proposed rule defined a permittee as a person; the final rule defines a permittee as a person or other legal entity.

The final rule defines ''protection'' in the context of the overarching purpose of the rule, which is to promote the use of conservation measures to support the ecosystem resilience of public lands. ''Protection'' is a critical component of conservation, alongside restoration, and describes acts or processes that keep resources safe from degradation, damage, or destruction. The rule (§ 6101.2(b)) would include a stated objective to promote the protection of intact landscapes on public lands as a critical means to achieve ecosystem resilience. The BLM received comments that requested clarification of the term protection and recommended distinguishing between protection and preservation. Commenters suggested removing the term preserve from the definition of protection, and commenters were concerned that the term protection, as it was defined in the proposed rule, was intended to set land aside and preclude other uses. The definition of protection was updated in the final rule to clarify that protection is not synonymous with preservation and is not intended to prevent active management or other uses.

The rule defines ''public lands'' in order to clarify the scope of the proposed rule and its intended application to all BLM-managed lands and uses. The definition is similar to the definition of ''public lands'' that appears at 43 CFR 6301.5, but the BLM has modified the definition from the proposed rule in response to comments to clarify that this rule extends only to BLM-managed surface estate. The resulting definition in this rule is specific to new part 6100 and should not be interpreted as changing the definition of ''public lands'' in any other context, including where that term would extend to BLM-managed mineral estate under other BLM regulations.

The rule defines ''reclamation'' to identify restoration practices intended to achieve an outcome that reflects project goals and objectives, such as site stabilization and revegetation. While ''reclamation'' is a part of a continuum of restoration practices, it contrasts with other actions that are specifically designed to recover ecosystems that have been degraded, damaged, or destroyed. Reclamation often involves initial practices that can prepare projects or sites for further restoration activities. The rule, at § 6102.4.2, discusses reclamation in the context of bonding restoration and mitigation leases to ensure lessees hold sufficient bond amounts to provide for the reclamation of the lease areas and the restoration of any lands or surface waters adversely affected by lease operations. The BLM made no changes to the definition from the proposed rule.

The final rule defines ''restoration'' in the context of the overarching purpose of this rule, which is to promote the use of conservation to ensure the ecosystem resilience of public lands. ''Restoration'' is a critical component of conservation, alongside protection, and describes acts or processes of conservation that passively or actively assist the recovery of an ecosystem that has been degraded, damaged, or destroyed. The BLM received comments suggesting that the rule acknowledge both passive and active restoration as legitimate restoration methods and comments calling for the clarification of what the BLM's broad-scale recovery goals are for restoration. Specifically, commenters identified the need to be explicit about the goal of returning ecosystems to a more natural, native ecological state and that the use of nonnative species in restoration projects is not the preferred option. The definition of restoration was updated in the final rule to include both active and passive restoration and to clarify that the goal of restoration efforts is the recovery of an ecosystem to a more natural, native ecological state.

The final rule adds a definition for the term ''significant causal factor'' because the rule uses this term to trigger an obligation on the part of the BLM to take appropriate action, including through the modification of authorizations and management practices for relevant programs and uses, in order to achieve land health. A significant causal factor is a use, activity, or disturbance that prevents an area from achieving or making significant progress toward achieving one or more land health standards. The rule requires the BLM to document a determination of the significant causal factor in circumstances in which resource conditions are not achieving or making significant progress toward achieving land health standards. If the BLM determines that existing management is a significant causal factor preventing achievement of land health standards, authorized officers must take appropriate action as soon as practicable.

The final rule adds a definition for the term ''significant progress,'' which is used in the rule as the measure of satisfactory progress toward achieving land health standards. Many comments requested clarification of this term, and while it is impractical to quantify the magnitude or rate of change that constitutes significant progress, the BLM developed a qualitative definition for purposes of implementing the rule. The term is defined to mean measurable or observable changes in the indicators that demonstrate improved land health. Acceptable levels of change must be realistic in terms of the capability of the resource but must also be as expeditious and effective as practical.

The final rule bases its definition of ''sustained yield'' on the FLPMA definition of that same term. This rule facilitates the use of conservation to achieve resilient ecosystems on public lands, which are essential to managing for multiple use and sustained yield. The BLM received comments suggesting the definition be updated to incorporate more precisely the language of the statutory definition, as well as comments recommending combining the definitions of sustained yield and multiple use and incorporating non-renewable resources into the definition of sustained yield. The final rule updates the definition of sustained yield to remain focused on renewable resources and responsible development of non-renewable resources and to add ''consistent with multiple use'' to mirror the FLPMA definition of sustained yield.

In response to public comments, the final rule expands the definition of ''unnecessary or undue degradation'' to address its distinct elements of ''unnecessary degradation'' and ''undue degradation''; and confirms that the statutory obligation to prevent ''unnecessary or undue degradation'' applies when either unnecessary degradation or undue degradation, and not necessarily both, is implicated. The rule explains that ''undue degradation'' is harm to land resources or values that is excessive or disproportionate to the proposed action or an existing disturbance. For example, approving a

proposed access road through the only remaining critical habitat for a plant listed as endangered under the Endangered Species Act, even if there is not another location for the road, would generally (although not always) result in undue degradation. The rule explains that ''unnecessary degradation'' is harm to land resources or values that is not needed to accomplish a use's stated goals. For example, approving a proposed access road through critical habitat for a plant listed as endangered under the Endangered Species Act that could be located elsewhere without impacting critical habitat and still provide the needed access would generally (although not always) result in unnecessary degradation.

This definition is consistent with BLM's affirmative obligation under FLPMA to take action to prevent unnecessary or undue degradation, which applies when either unnecessary degradation or undue degradation, and not necessarily both, is implicated. The definition of ''unnecessary or undue degradation'' applies to the use of those terms in the part 6100 regulations promulgated by this rule. It does not alter the definition of the term ''unnecessary or undue degradation'' at § 3809.5 of this chapter and does not apply to that term's use in the regulations at subpart 3809 of this chapter.

The final rule adds a definition for ''watershed condition assessment,'' which is defined to mean a process for assessing and synthesizing information on the condition of soil, water, habitats, and ecological processes within a watershed following the land health fundamentals through consideration of the watershed's physical and biological characteristics, landscape intactness, and disturbances. Watershed condition assessments are equivalent to the ''watershed condition classifications'' and ''land health assessments'' discussed in the proposed rule. The final rule updates the term and provides this definition in response to many public comments seeking clarification and efficiency of process.

Section 6101.5—Principles for Ecosystem Resilience

The rule relies upon express direction provided in FLPMA to manage public lands on the basis of multiple use and sustained yield, and it establishes the principle that the BLM must conserve renewable natural resources at a level that maintains or improves ecosystem resilience in order to achieve this mission. The BLM made only minimal changes to this section from the proposed rule.

Section 6101.5(d) directs authorized officers to implement principles of ecosystem resilience by recognizing conservation as a land use within the multiple use framework, including in decision-making, authorizations, and planning processes; protecting and maintaining the fundamentals of land health; restoring and protecting intact public lands; applying the full mitigation hierarchy to address impacts to species, habitats, and ecosystems from land use authorizations; and preventing unnecessary or undue degradation.

Subpart 6102—Conservation Use To Achieve Ecosystem Resilience

The rule clarifies that conservation is a use on par with other uses of public lands under FLPMA's multiple use framework. FLPMA directs the BLM to manage the public lands in a manner that protects the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archaeological values, among other resources and values, and that protects certain public lands in their natural condition. The BLM implements this mandate through land use plan allocations, including designations, and other planning decisions that conserve public land resources, seeking to balance conservation uses with other uses, such as energy development and recreation. The BLM also complies with this mandate when issuing decisions that implement its land use plans. In these implementation decisions, including when authorizing projects, the BLM promotes conservation use by requiring appropriate mitigation of impacts to natural resources on public lands. The rule provides specific direction for implementing certain programs in a way that emphasizes conservation use and provides new tools and direction for managing conservation use to facilitate ecosystem resilience on public lands.

As described in detail in each section, the BLM updated the final rule in response to public comments to clarify processes, including how conservation uses would occur within and outside of land use planning processes; enumerate guiding principles for restoration and mitigation actions; and provide other adjustments to improve public understanding and agency implementation of the rule. The most significant change to this subpart is that the final rule establishes restoration and mitigation leases as two separate types of leases instead of providing simply for conservation leases available for both purposes (which was the approach in the proposed rule). The final rule expands the regulations governing these leases to provide a more comprehensive framework for implementation and respond to concerns heard from the public.

Section 6102.1—Protection of Landscape Intactness

The BLM changed the title of § 6102.1 from ''Protection of Intact Landscapes'' in the proposed rule to ''Protection of Landscape Intactness'' in the final rule. Public comments suggested that the rule distinguish intactness as a resource value from intact landscapes as delineated units. The change in the title of § 6102.1 reflects that landscape intactness is the resource value that the BLM is seeking to identify and protect. The final rule includes a definition of the term ''intactness'' to further guide implementation of this section. Section 6102.1(a) and (b) require the BLM to manage certain landscapes to protect their intactness and to seek to prioritize actions that conserve and protect landscape intactness. The following section, 6102.2, provides direction for the BLM to inventory and protect intactness on the public lands by identifying and managing intact landscapes in the land use planning process.

Section 6102.2—Management To Protect Intact Landscapes

The BLM revised § 6102.2 in response to public comments requesting clarity around how intact landscapes would be identified and managed within and outside of the land use planning process and to distinguish intactness as a resource value from intact landscapes as delineated units. The final rule establishes in § 6102.2(a) that the BLM will maintain an inventory of intactness on the public lands, in accordance with FLPMA's requirement that the BLM maintain an inventory of all public lands and their resources and other values.

In the land use planning process, § 6102.2(b) requires the BLM to use the intactness inventory, and other available information including habitat connectivity and migration corridor data, to identify intact landscapes, evaluate alternatives to manage intact landscapes, and identify which intact landscapes or portions of intact landscapes will be managed for protection. Furthermore, in the land use planning process, § 6102.2(c) requires the BLM to identify desired conditions and landscape objectives to guide implementation decisions regarding management of intact landscapes. In making management decisions for intact landscapes, the BLM will seek to work

with communities to identify the most suitable areas to protect as intact landscapes; consult with Tribes to identify opportunities for co-stewardship; establish partnerships; and monitor effectiveness of ecological protection activities.

In addition to the land use planning process described above, § 6102.2(d) requires authorized officers to prioritize acquisition of lands or interests in lands that would further protect and connect intact landscapes and functioning ecosystems, and § 6102.2(e) directs the BLM to develop a national system for collecting and tracking disturbance and intactness data and to use those data to minimize disturbance and improve ecosystem resilience. Data will be made available to the public.

Section 6102.3—Restoration

In the proposed rule, restoration was divided across three sections (Restoration, Restoration Prioritization, and Restoration Planning). The final rule keeps a Restoration section but combines the remaining two sections into a Restoration Prioritization and Planning section. The definition of restoration, critical to interpretation of this section, has been updated to provide that restoration actions include both passive and active measures that assist the recovery of an ecosystem that has been degraded, damaged, or destroyed. The definition has been further updated to clarify that the intent of restoration actions is the return of more natural, native ecological states. The final rule emphasizes the importance of restoration in achieving multiple use and sustained yield and requires a consideration of the causes of degradation, the recovery potential of an ecosystem, and the allowable uses in the governing land use plan, such as whether an area is managed for recreation or is degraded land prioritized for development, in determining restoration actions. Principles for restoration actions, which were previously located in the Restoration Planning section of the proposed rule, are now found in the Restoration section to clarify that such principles apply to all restoration actions.[14] The principles include direction to consult with Tribes to identify opportunities for co-stewardship or collaboration, similar to the direction provided for managing intact landscapes.

[14] The reference to ''low-tech restoration activities'' in section 6102.3(d) means the practice of using simple, low unit-cost, structural additions (*e.g.,* wood and beaver dams in streams) to mimic natural functions and promote specific processes.

Section 6102.3.1—Restoration Prioritization and Planning

A combined restoration prioritization and planning section at 6102.3.1 requires the identification of restoration outcomes in resource management plans. Consistent with these outcomes, the section requires the identification of priority landscapes for restoration at least every 5 years and provides for a number of considerations for authorized officers when doing so. The section requires the development of restoration plans at least every 5 years and enumerates criteria with which restoration goals, objectives, and management actions identified in the plans must adhere. Among other criteria, restoration plans must adhere to commonly accepted principles and standards within the field of ecological restoration. Lastly, the section requires authorized officers to track restoration implementation and progress against identified goals and assess why restoration outcomes are not being met and what, if anything, is additionally needed to achieve restoration goals.

Section 6102.4—Restoration and Mitigation Leasing

Section 302(b) of FLPMA (43 U.S.C. 1732(b)) grants the Secretary authority to regulate through appropriate instruments the use, occupancy, and development of the public lands. Under that broad authority, the rule provides a framework for the BLM to issue restoration and mitigation leases on public lands for the purpose of pursuing ecosystem resilience through mitigation and restoration actions. The BLM will determine whether a lease is an appropriate mechanism based on the context of each application for a proposed lease, consistent with the final rule.

The BLM received many comments on the leasing provisions in the proposed rule that resulted in changes in the final rule. These changes include: establishing restoration leases and mitigation leases rather than conservation leases, which as proposed would have been used for either purpose; enabling conservation districts and State fish and wildlife agencies to hold leases; including consideration of factors to incentivize lease proposals that collaborate with existing permittees and other affected interests and meet other desirable criteria; requiring lessees to report annually on lease activity; and providing for the BLM to waive or reduce the rent of a restoration lease if the lease is providing valuable benefit to the public lands and is not generating revenue.

Many commenters were concerned about public access to public lands that are leased for restoration or mitigation purposes and expressed concern that the rule's definition of ''casual use'' does not explicitly guarantee use for common activities. While the BLM did not change the definition of ''casual use'' in order to remain consistent with existing regulations, the final rule specifically states that a restoration or mitigation lease will not preclude access to or across leased areas for recreation use, research use, or other authorized use that is compatible with the restoration or mitigation activities.

Some commenters questioned whether the BLM through this rulemaking or subsequent land use planning would allocate public lands as available to or excluded from restoration and mitigation leasing. The final rule does not identify or limit public lands that could be leased for restoration or mitigation purposes. However, several provisions guide the evaluation of which lands are suitable for leasing. The rule requires the BLM to identify restoration priority landscapes, intact landscapes, and landscape-scale mitigation strategies, and these areas would be logical locations for leases to support restoration and mitigation efforts the agency is prioritizing. The rule also enumerates factors for evaluating lease proposals based on criteria that are expected to make leases more successful. The rule does not allow for leases to be issued where an existing, authorized, and incompatible use is occurring, effectively removing areas from consideration for at least some activities that could be authorized by a restoration or mitigation lease. Additionally, any restoration or mitigation lease would need to conform to the BLM's approved land use plan. These provisions collectively guide restoration and mitigation leases to the most suitable locations without requiring the BLM, in every instance, to undertake a plan amendment or revision to allocate lands as available for leasing.

The following paragraphs summarize the restoration and mitigation leasing provisions in the final rule.

Section 6102.4(a) authorizes the BLM to issue restoration and mitigation leases for the purpose of restoring degraded landscapes or mitigating impacts resulting from other land use authorizations. Entities that can hold restoration and mitigation leases include individuals, businesses, non-governmental organizations, Tribal governments, conservation districts, and State fish and wildlife agencies. Qualified entities for a mitigation lease to establish an in-lieu fee program

would be limited to non-governmental organizations, State fish and wildlife agencies, and Tribal government organizations. Leases cannot be held by foreign persons as that term is defined in 31 CFR 802.221. The BLM will rely on standard lease adjudication practices established in 43 CFR 2920 to determine if a lease applicant meets the preconditions in this part for a qualified entity. Restoration and mitigation leases will be issued for the necessary amount of time to meet the lease objective. A lease issued for restoration purposes can be issued for an initial term of up to 10 years, whereas a lease issued for mitigation purposes will be issued for a term commensurate with the impact it is mitigating. Activity on all leases will be reviewed for consistency with lease provisions at regular intervals and can be extended beyond their primary terms when extension is necessary to serve the purpose for which the lease was first issued. Section 6102.4(a)(4) precludes the BLM from issuing new authorizations to use the leased lands if the use would be incompatible with the authorized restoration or mitigation use set forth in the lease.

Section 6102.4(b) and (c) set forth the application process for restoration and mitigation leases. Applicants are required to submit detailed restoration or mitigation development plans that include information on outreach with existing permittees, lease holders, adjacent land managers or owners, and other interested parties. The authorized officer can require additional information such as environmental data and proof that the applicant has the technical and financial capability to perform the restoration and mitigation activities.

Section 6102.4(d) enumerates factors for the authorized officer to consider when evaluating a lease application. Those factors include: lease outcomes that are consistent with restoration principles established in the rule; lease outcomes tied to desired future conditions that are consistent with the management objectives and allowable uses in the governing land use plan, such as an area managed for recreation or degraded land prioritized for development; collaboration with existing permittees, leaseholders, and adjacent land managers or owners; outreach to or support from local communities; and consideration of environmental justice objectives.

Once a lease application is approved, § 6102.4(e) requires the applicant to provide the BLM with a monitoring plan and to report annually and at the end of the lease period on lease activity.

Section 6102.4(f) and (g) provide that restoration and mitigation leases do not entitle leaseholders to the exclusive use of the public lands and that other uses compatible with the objectives of the restoration or mitigation lease are explicitly allowed on leased lands. Consistent with other land use authorizations, such as rights-of-way, it is the BLM's view that no property interest is conveyed by issuing these leases. Section 6102.4(g) confirms that a restoration or mitigation lease will not preclude access to or across leased areas for casual use, recreation use, research use, or other use taken pursuant to a land use authorization that is compatible with the approved restoration or mitigation use.

Section 6102.4(j) directs that cost recovery, rents, and fees for restoration and mitigation leases will be governed by existing regulations at 43 CFR 2920.6 and 2920.8 and that the BLM will generally collect annual rental based on fair market value. Recognizing that restoration lessees are providing a service to the public and the BLM, the rule provides for waiving or reducing the rent of a restoration lease if a valuable benefit is being provided to the public and revenue is not being generated. This approach is consistent with the approach in waiving rents for rights-of-way in 43 CFR 2806.15. Although section 102 of FLPMA provides a policy preference for recovering fair market value for the use of the public lands (*see* 43 U.S.C. 1701(a)(9)), the BLM is not required to do so, especially in circumstances in which departing from charging a fair market value rent would further other policy priorities identified in section 102 of FLPMA. Here, the BLM has determined that allowing authorized officers the discretion to reduce or waive rent for restoration leases will assist in its effort to manage the public lands to protect the quality of ecological and other relevant values. (*See* 43 U.S.C. 1701(a)(8))

Section 6102.4.1—Termination and Suspension of Restoration and Mitigation Leases

The final rule makes only minimal changes to § 6102.4.1 from the proposed rule. Section 6102.4.1 outlines processes for suspending and terminating restoration and mitigation leases. Where the leaseholder fails to comply with applicable requirements, fails to use the lease for its intended purpose, or cannot fulfill the lease's purpose, the BLM may suspend or terminate the lease. An authorized officer must issue an immediate temporary suspension of a lease upon determination that a noncompliance issue adversely affects or poses a threat to public lands or public health or safety. Following termination of a lease, the leaseholder has sixty days to fulfill its obligation to reclaim the site (*i.e.,* return the site to its prior condition or as otherwise provided in the lease). That obligation is distinct from the goal of restoring the site to its ecological potential that underlies the lease.

Section 6102.4.2—Bonding for Restoration and Mitigation Leases

The final rule authorizes the BLM to require a bond for a restoration or mitigation lease involving surface-disturbing or active management activities, but does not require a bond in all cases as the proposed rule would have. Section 6102.4.2(a) directs that for mitigation leases, the lease holder will usually be required to provide letters of credit or establish an escrow account for the full amount needed to ensure the development plan meets all performance criteria. The final rule includes considerations for requiring a bond, such as the type and intensity of surface-disturbing activities, proposed use of experimental or non-natural restoration methods, and risks associated with the proposed actions.

Section 6102.4.2(b) through (d) establishes additional bonding provisions regarding statewide bonds, filing of bonds, and default and are unchanged from the proposed rule.

Section 6102.5—Management Actions for Ecosystem Resilience

The final rule includes minor updates to this section in response to comments suggesting more clarity around how the section connects to other sections of the rule. Commenters also recommended strengthening the focus on ecosystem resilience and emphasizing biodiversity as an important component of ecosystem resilience. This rule focuses primarily on supporting healthy and resilient ecosystems, which are the basis for multiple use and sustained yield and which, if achieved, will benefit biodiversity, water security, carbon sequestration, forage, and a host of other values.

Section 6102.5 sets forth a framework for the BLM to make informed management decisions based on science and data, including at the planning, permitting, and program levels, that would help to facilitate ecosystem resilience. As part of this framework, authorized officers are required to identify priority watersheds, landscapes, and ecosystems that require protection and restoration efforts; develop and implement protection,

restoration, mitigation, monitoring, and adaptive management strategies; [15] and share watershed condition assessment data with the public. The final rule cross-references these requirements listed in § 6102.5(a) with other sections of the rule that provide additional guidance on these management actions for ecosystem resilience.

Section 6102.5(b) requires the BLM to meaningfully consult with Tribes and Alaska Native Corporations and makes a change from the proposed rule that provides for Tribal input on whether actions are likely to substantially impact Tribes or Alaska Native Corporations. The rule also requires the BLM to respect and include Indigenous Knowledge in decision-making, including through Tribal co-stewardship, and updates provisions and definitions in the rule to reflect current departmental and agency guidance.

Consistent with applicable law and resource management plans, including, for example, where an area is managed for recreation or is degraded land prioritized for development, authorized officers are required to make every effort to avoid authorizing any use of the public lands that permanently impairs ecosystem resilience. Permanent impairment of ecosystem resilience would be difficult or impossible to avoid, for example, on lands on which the BLM has authorized intensive uses, including infrastructure and energy projects or mining, or where the BLM has limited discretion to condition or deny the use. Through this frame, the rule recognizes that the BLM may develop land use plans that prioritize degraded areas for development, such as in the Arizona Restoration Design Energy Project, or generally prioritize areas for utility-scale development, such as the Solar Energy Zones designated in the 2012 Western Solar Plan, and that the effects on ecosystem resilience in such a plan may be mitigated but will not be completely avoided. The rule also requires the authorized officer to provide justification for decisions that may impair ecosystem resilience. In other words, the rule does not prohibit land uses that impair ecosystem resilience; it requires avoidance as a general matter and an explanation if impairment cannot be avoided.

[15] Adaptive management is a system of management practices based on clearly identified outcomes and monitoring to determine whether management actions are meeting desired outcomes and, if not, facilitating management changes that will best ensure that outcomes are met or reevaluated. Adaptive management recognizes that knowledge about natural resource systems is sometimes uncertain (43 CFR 46.30).

To ensure the best available science is underpinning management actions, the rule requires the BLM to use national and site-based assessment, inventory, and monitoring data, along with other high-quality information, to evaluate resource conditions and inform decision-making.

Section 6102.5.1—Mitigation

The rule at § 6102.5.1(a) directs the BLM to apply the mitigation hierarchy to avoid, minimize, and compensate for adverse impacts to all public land resources, generally in that order. The rule states further that mitigation approaches or requirements may be identified in land use plans or other decision documents. Consistent with BLM's existing policy on mitigation (H–1794–1), which requires BLM to consider compensatory mitigation for important, scarce, or sensitive resources, § 6102.5.1(b) expands upon this direction by requiring that mitigation to address adverse impacts to such resources should be applied with the goal of eliminating, reducing, and/or offsetting impacts on the resource, consistent with applicable law. This facilitates BLM's compliance with its multiple-use and sustained yield mission by conserving such resources for future generations. Determining the maximum benefit to an impacted resource from a compensatory measure is often achieved by carefully identifying the type, location, timing, and other aspects of the compensatory mitigation measure. This assessment is conducted as standard practice in the BLM's NEPA analysis and decision documents.

The rule also identifies new principles at § 6102.5.1(c) to apply when implementing mitigation, including the need to ensure compensatory mitigation is commensurate with the impacts, and the use of adaptive management, landscape-scale approaches, high-quality information, and performance criteria and effectiveness monitoring.

At § 6102.5.1(d), the rule allows the BLM to approve and use third-party mitigation fund holders to administer funds for the implementation of compensatory mitigation programs or projects and specifies the type of actions third parties can perform with compensatory mitigation funding. Section 6102.5.1(e) establishes the requirements for different types of entities that could be considered and approved as mitigation fund holders. The mitigation fund holder could be a State or local government, if, among other requirements, that entity can demonstrate to the satisfaction of the BLM that it is acting as a fiduciary for the benefit of the mitigation project and site. The section also allows for a mitigation fund holder to be an entity that, among other requirements, qualifies for tax-exempt status and provides evidence it can successfully hold and manage mitigation accounts.

Sections 6102.5.1(f) through (i) provide further direction to authorized officers in managing mitigation leases and lease holders, including provisions to govern the collection of annual rent at fair market value for large or otherwise substantial compensatory mitigation programs or projects on public lands, including mitigation banks and in-lieu fee programs.

Subpart 6103 Managing Land Health To Achieve Ecosystem Resilience

Section 6103.1—Land Health Standards

Consistent with the proposed rule, § 6103.1 of the final rule directs that all program areas of the BLM must be managed in accordance with the fundamentals of land health, which are adopted, verbatim, from the fundamentals of rangeland health included at 43 CFR 4180.1 (2005). It does so by establishing a series of procedural requirements to guide the BLM's actions to address land health. The rule does not require that individual actions ''comply'' with the fundamentals of land health, nor does it require achievement of those fundamentals (as measured by the land health standards) as a precondition for any BLM decision.

The rule in this section directs authorized officers to adopt national land health standards across all ecosystems that provide consistency and conformance with the fundamentals of land health and facilitate progress toward meeting land health. Acknowledging the importance of standards in managing all of the BLM's programs in accordance with the fundamentals, the title of § 6103.1 has been changed to Land Health Standards. Section 6103.1 includes a new paragraph (b) describing the resources, processes, and values addressed through national land health standards as well as a new timeline at paragraph (e) to review and amend or supplement standards and a subsequent timeline to ensure standards remain sufficient. A new paragraph at § 6103.1(d) instructs authorized officers to incorporate geographically distinct land health standards when needed to address unique or rare ecosystem types that may not be addressed by the national standards. These new timelines in the final rule—along with additional

implementation specificity found in other land-health related sections of the rule—are introduced in response to comments that sought more clarity and specificity for how standards may be updated to serve as appropriate measures for the fundamentals. Section 6103.1(f) makes explicit that any new or amended land health standard must be approved by the BLM Director prior to implementation.

Section 6103.1.1—Management for Land Health

Section 6103.1.1(a) conveys the importance of assessing land health at a broad scale to manage for ecosystem resilience and provides that authorized officers should rely on assessments and evaluations conducted at such scales, as appropriate, to support decision-making. Section 6103.1.1(b) reinforces the direction that all BLM program areas must be managed to facilitate progress toward achieving land health standards. Section 6103.1.1(b)(1) requires authorized officers to apply existing standards in the administration of all BLM programs. Initially, this will mean applying the existing standards prepared pursuant to subpart 4180 of this chapter to all programs, *not just* grazing. Moving forward, consistent, national standards will be completed pursuant to procedures set out in this subpart, and not under the procedures set out in subpart 4180, and will then apply to all programs, *including* grazing. Section 6103.1.1(b)(2) directs programs to develop management guidelines, which are best practices in managing programs to achieve goals. Management guidelines are to be reviewed at least every 10 years consistent with review timelines in other sections that relate to land health. As with standards, existing management guidelines applicable to the grazing program will continue to apply. New and amended guidelines for grazing should be developed under the procedures in this subpart, and not subpart 4180. Sections 6103.1.1(c) and (d) require that land health be included in land use planning, primarily when identifying allocation decisions and actions that are anticipated to achieve land health outcomes, as well as any impediments in doing so.

Section 6103.1.2—Land Health Evaluations and Determinations

Section 6103.1.2(a) has been modified to require that authorized officers complete watershed condition assessments and land health evaluations at least every 10 years. Watershed condition assessments supplant land health assessments in the proposed rule and characterize resource conditions, while subsequent land health evaluations interpret assessment findings to draw conclusions about whether land health standards are being achieved consistent with the fundamentals of land health. This efficiency of process responds to many comments and concerns about the BLM's ability to complete land health assessments across broad spatial scales.

Direction to conduct watershed condition assessments and land health evaluations at broader spatial scales, as opposed to at the scale of an allotment or other more narrowly drawn boundary or project area, builds on best practices currently deployed by BLM field offices, responds to comments recommending landscape-scale approaches as a way to address the backlog of pending land health assessments and evaluations, and better serves efforts to understand and address land health conditions across management boundaries.

Section 6103.1.2(d) provides what must be incorporated when conducting land health evaluations, such as watershed condition assessments and high-quality information requirements. Section 6103.1.2(d) further clarifies the requirements for conducting land health evaluations, including that authorized officers document the rationale and findings as to whether each land health standard is achieved or making significant progress towards achievement.

Sections 6103.1.2(e), (f), and (g) describe the process after land health evaluations determine if resource conditions are or are not achieving or making significant progress toward achieving land health standards. When watershed condition assessments and land health evaluations find that resource conditions are achieving or making significant progress toward achieving land health, then project-level decisions should rely on such evidence where possible and appropriate. Section 6103.1.2(f) provides for tiering documentation and evidence from broad-scale assessments and evaluations for project-level decisions, such as grazing permit renewals, which promotes efficiency and streamlines decision-making. This provision responds to comments concerned with the existing backlog of assessments land health evaluations.

When watershed condition assessments and land health evaluations find that resource conditions are not achieving, or making significant progress toward achieving, land health standards, then causal factor determinations, as directed by § 6103.1.2(f), must be prepared no later than a year after the evaluation. Determinations document significant causal factors for non-achievement. Section 6103.1.2(f)(3) requires authorized officers to take appropriate action as soon as practicable to address nonachievement of land health standards when the significant causal factors include existing management practices or levels of use on public lands. However, as clarified in § 6103.1.2(f)(4), to the extent existing grazing management practices or levels of grazing use on public lands are significant causal factors preventing achievement of land health standards, authorized officers must also comply with the requirement for taking appropriate action set by § 4180.2(c) of this chapter, including that appropriate action be taken not later than the start of the next grazing year.

Further, as noted previously, appropriate actions in a specific situation will be informed and may be constrained by applicable law and the governing land use plan. For example, where a land use planning approach, such as BLM Arizona's Restoration Design Energy Project, is intended to support development of renewable energy on disturbed or previously developed sites, then appropriate actions would be designed to add measures that facilitate the progress of the affected lands toward meeting the applicable fundamentals of land health. However, these actions would be informed by the overall approach of identifying disturbed lands suitable for renewable energy development and applying measures consistent with those management decisions. This is consistent with the approach to incorporate design features into the Restoration Design Energy Project Record of Decision to reduce overall impacts to the lands identified for development. (See *https://eplanning.blm.gov/public_projects/nepa/79922/107093/131007/RDEP-ROD-ARMP.pdf*).

Section 6103.1.2(f)(5) identifies some appropriate actions that may be deployed to address practices and uses determined to be significant causal factors, consistent with applicable law, regulation, and the governing resource management plan and its management objectives, such as where an area is managed for recreation or is degraded land prioritized for development. For example, if a governing resource management plan identifies degraded lands for solar development and those areas are not meeting standards, the authorized officer should consider that land use planning decision in determining the appropriate action. In that circumstance, it would typically

not be appropriate to deny solar or wind use altogether, although design features or other mitigation measures may be applied. Section 6103.1.2(i) reinforces that appropriate actions must be consistent with existing resource management plans and notes that if planning decisions do not allow for appropriate actions to address significant causal factors, then an authorized officer may decide to amend or revise the applicable land use plan. However, whether to undertake a planning process is at the discretion of the authorized officer. Sections 6103.1.2 (j) and (k) respond to public comment by requiring annual, publicly available reporting on assessment, evaluation, and determination accomplishments; results; and actions.

Section 6103.2—Inventory, Assessment, and Monitoring

The final rule requires the BLM to complete watershed condition assessments every 10 years and consider them in multiple decision-making processes. New paragraphs at § 6103.2(a) further describe the purpose, process, and requirements of conducting watershed condition assessments in support of land use planning, protection of intact landscapes, managing for ecosystem resilience, informing restoration actions, and informing land health evaluations and determinations. In response to public comments encouraging consistency in analysis approach, standard data sources, and transparency, the final rule adds in § 6103.2(a) that the BLM must utilize multiple sources of high-quality information to understand conditions and trends relevant to land health standards and incorporate consistent analytical approaches, quantitative indicators, and benchmarks where practicable. It is anticipated that watershed condition assessments will frequently be completed not by BLM State Offices, but by national-level resources, such as the National Operations Center, utilizing standardized procedures and existing data and analyses and validated with local data and high-quality information as appropriate.

Section 6103.2(b) clarifies that the BLM's inventory of public lands includes both landscape components and core indicators that address land health fundamentals and requires the use of high-quality information and inventory, assessment, and monitoring information, including standardized quantitative monitoring data, remote sensing maps, and geospatial analyses, to inform decision-making across program areas. In response to public comments, the BLM clarified that this inventory specifically includes infrastructure and renewable resources and that it is available to the public (currently, *https://gbp-blm-egis.hub.arcgis.com/*). Section 6103.2(c) establishes principles to ensure that inventory, assessment, and monitoring activities are evidence-based, standardized, efficient, and defensible.

43 CFR Chapter II

Subpart 1610—Resource Management Planning

Section 1610.7–2—Designation of Areas of Critical Environmental Concern

The rule includes changes to the land use planning regulations to elaborate on the role ACECs play as the principal administrative designation for public lands where special management attention is required to protect important natural, cultural, and scenic resources and to protect against natural hazards. It reiterates FLPMA's requirement that the BLM give priority to the identification, evaluation, and designation of ACECs during the land use planning process and provides additional clarity and direction for complying with this statutory requirement. The rule codifies in regulation procedures for considering and designating potential ACECs that were, prior to promulgation of this rule, partially described in regulation and partially described in agency policy.

The BLM received many comments on the ACEC provisions of the proposed rule, and the final rule reflects changes the BLM made based on public comments. As described in more detail below, changes from the proposed rule include: providing for the BLM to implement temporary management for potential ACECs identified outside of an ongoing planning process, with public notice and periodic reevaluation; codification of research natural areas as a type of ACEC designated for the primary purpose of research and education on public lands, consistent with existing regulations and policy; a presumption that all areas found to meet all three ACEC criteria will be designated in the resource management plan; a management standard that requires the BLM to administer designated ACECs in a manner that conserves, protects, and enhances the relevant and important values; and a definition for the term ''irreparable damage.''

The final rule also confirms that proposed and existing ACECs being addressed in the planning process for a resource management plan or a plan amendment will be identified in all applicable **Federal Register** Notices and in public outreach materials. The BLM will not be required to produce separate notices specific to ACECs. The following paragraphs summarize the ACEC provisions in the final rule.

Section 1610.7–2(a) confirms that ACECs are the principal administrative designation for public lands where special management is required to protect and prevent irreparable damage to important resources. ACECs are considered and designated in land use planning processes, including resource management plan revisions and amendments.

Section 1610.7–2(b) requires authorized officers to identify, evaluate, and give priority to areas that have potential for designation and management as ACECs in the land use planning process, and it provides that proposed and existing ACECs that will be addressed in the planning process for a resource management plan, plan revision, or plan amendment will be identified in all applicable public notices.

Section 1610.7–2(c) requires authorized officers to identify areas that may be eligible for ACEC status early in the planning process and specifies the need to target areas for evaluation based on resource inventories, internal and external nominations, and existing ACEC designations.

Section 1610.7–2(d) outlines the three criteria that must be met for ACEC designation, which are relevance, importance, and special management attention. The rule provides that values and resources may have importance if they contribute to ecosystem resilience, landscape intactness, or habitat connectivity, in addition to other importance criteria. The final rule requires that values and resources have more than local importance to meet the importance criteria, a change from the proposed rule based on public comments. Special management attention prevents irreparable damage to the relevant and important values and would not be prescribed if the relevant and important values were not present. The rule defines ''irreparable damage'' in this context to mean: ''harm to a value, resource, system, or process that substantially diminishes the relevance or importance of that value, resource, system, or process in such a way that recovery of the value, resource, system, or process to the extent necessary to restore its prior relevance or importance is impossible.'' Requiring a finding that special management attention is necessary for ACEC designation is consistent with BLM practice and guidance but was not a feature of the

regulations prior to promulgation of this rule.

Section 1610.7–2(e) provides that the BLM may designate an ACEC research natural area (RNA) for an area that meets all three ACEC criteria set forth in § 1610.7–2(e) and is consistent with the purposes for research natural areas established in existing regulations at 43 CFR subpart 8223. These regulations allow the BLM to establish RNAs for the primary purpose of research and education on public lands having natural characteristics that are unusual or that are of scientific or other special interest. The BLM's current guidance, as set forth in the agency's Land Use Planning Handbook and ACEC Manual, considers RNAs as a type of ACEC that are to be designated following the ACEC designation process. The BLM has designated many ACEC RNAs in existing land use plans following this guidance. Because this rule is codifying the BLM's ACEC guidance and process, and in response to public comments on this topic, the final rule provides for this RNA designation.

Section 1610.7–2(f) provides that the boundaries of proposed ACECs shall be identified for public lands as appropriate to encompass the relevant and important values and geographic extent of the special management attention needed to provide protection.

Section 1610.7–2(g) requires the BLM to analyze in detail all potential ACECs that have relevant and important values in planning documents. In the land use planning process, the BLM evaluates the need for special management attention to protect the relevant and important values of potential ACECs, which could include other allocations and designations that would provide appropriate protection and prevent irreparable damage to the relevant and important values.

Section 1610.7–2(h) directs that an approved resource management plan, plan revision, or plan amendment will list all designated ACECs, identify their relevant and important values, and include the special management attention being provided to them.

Section 1610.7–2(i) establishes procedures for addressing potential ACECs that are identified outside of an ongoing planning process. The State Director has the discretion to determine the appropriate time to evaluate whether the nomination meets the relevant, important, and special management criteria identified in 1610.7–2(d)(1) through (3). If a potential ACEC nomination meets all three criteria specified in the regulations—that is, it has relevance and importance and needs special management attention—then the State Director will, at their discretion, either initiate a land use planning process to evaluate the potential ACEC for designation or provide temporary management consistent with the existing resource management plan to protect the relevant and important values from irreparable damage. The final rule clarifies that the authorized officer in this context would be the State Director, consistent with other portions of the rule addressing decisions on potential ACECs. If the BLM decides to implement temporary management, the BLM will comply with all applicable laws, including NEPA, notify the public, and reevaluate the area periodically to ensure temporary management is still necessary. This provision does not change the presumption that ACECs are nominated and addressed through resource management planning processes, and it does not require the BLM to evaluate ACEC nominations outside the planning process.

Section 1610.7–2(j) requires the State Director to: determine which ACECs to designate based on specific factors including a presumption that all potential ACECs that meet all three criteria will be designated; provide a justification and rationale in decision documents for decisions both to designate an ACEC and not to designate an ACEC; administer designated ACECs in a manner that conserves, protects, and enhances the relevant and important values and only allow casual use or uses that will ensure the protection of the relevant and important values; and prioritize acquisition of inholdings within ACECs and adjacent or connecting lands that also possess the relevant and important values of a specific ACEC. In response to comments, the final rule eliminated the requirement included in the proposed rule that State Directors provide annual reports describing activity plans and implementation actions for each ACEC in the State. Such reporting is more appropriately developed during implementation of the final rule and should remain within the discretion of the State Director.

Section 1610.7–2(k) authorizes the State Director to remove an ACEC designation in a land use planning process only when special management attention is not needed because another legally enforceable mechanism provides an equal or greater level of protection, or when the relevant and important values are no longer present, cannot be recovered, or have recovered to the point where special management is no longer necessary.

Section 1610.7–2(l) identifies terms that are used in the ACEC section—casual use, conserve, ecosystem resilience, intactness, landscape, monitoring, protect, and restore—and provides that they should be interpreted consistent with the definitions of those same terms in § 6101.4.

Severability

The provisions of the rule should be considered separately. If any portion of the rule were stayed or invalidated by a reviewing court, the remaining elements would continue to provide the BLM with important and independently effective tools to advance conservation on the public lands. In particular, revisions to existing planning regulations at 43 CFR part 1600 governing the designation and management of ACECs are separate from the balance of the rule, which promulgates the new 43 CFR part 6100. Within part 6100, the rule includes a number of aspects that function independently and hold independent utility. For example, the rule's provisions pertaining to the identification and management of intact landscapes and other values in land use planning and agency decision-making; its framework for third-party restoration and mitigation leasing; and its procedures for adopting national land health standards, assessing land health, and using those assessments to drive agency decisions operate as independent means to achieve the rule's overarching goal of facilitating conservation of the public lands. Hence, if a court prevents any provision of one part of this rule from taking effect, that should not affect the other parts of the rule. The remaining provisions would remain in force.

IV. Additional Response to Public Comments

The BLM received an initial total of 216,403 comments from regulations.gov. Further analysis showed that there were public comment submissions with multiple cosigners, sometimes several thousand on one submission, which were initially counted as separate submissions but ultimately identified as a single submission with multiple signatures. Therefore, although 216,403 voiced their opinion, the final count of comment letters came to 152,673. The comment letters on the proposed rule are available for viewing on the Federal e-rulemaking portal (*https://www.regulations.gov*) (search Docket ID: BLM–2023–0001).

The BLM has reviewed all public comments in the context of the proposed rule and the particular

solicitations for comment in its preamble. The BLM has made changes to the final rule based on the public comments that refine and further develop the concepts identified in the proposed rule. The BLM did not make wholesale changes or additions, even when prompted to do so by the public comments, that would have caused the final rule to materially alter the issues included in or substantially depart from the terms and substance of the proposed rule. Changes made are described in this section and the ''Section-by-Section Discussion of Final Rule and Revisions from the Proposed Rule'' section.

The following is a summary of significant issues raised in comments the BLM received on the proposed rule and responses to these comments. The comments highlighted in the following paragraphs fell into several categories: comments related to sections of the proposed rule; comments related to public lands uses and resources not addressed in the rule; and comments on the rulemaking process. See the Section-by-Section discussion for responses to public comments on specific sections of the proposed rule.

A. Conservation Leasing

Commenters generally sought a better understanding of many aspects of the conservation leasing proposal, including the purposes and uses of the leases, and identified the need for terminology that better reflects those purposes and uses. Commenters requested additional detail within the rule text for what would and would not be allowed under a conservation lease, clarification on the terms and duration of the leases, and information on how conservation leases would interact with existing uses such as grazing and recreation.

In response to these comments, the BLM updated the rule to provide clarity and specificity for the leasing program being established in the rule. Significantly, the final rule establishes two distinct types of leases in place of referring to ''conservation leases'': restoration leases and mitigation leases. Restoration leases can be used to facilitate restoration of land and resources by passively or actively assisting the recovery of an ecosystem; and mitigation leases can be used to offset impacts to resources resulting from other land use authorizations. Restoration can occur under a mitigation lease when restoration is a mitigation action being taken pursuant to the lease. The final rule enumerates factors for authorized officers to consider when evaluating lease proposals, such as whether the applicant is collaborating with existing permittees, whether the lease would advance environmental justice objectives, or whether the objectives of the proposed leases would be supported by current management of the lands. The final rule also enables conservation districts and State fish and wildlife agencies to hold restoration and mitigation leases and specifies that recreation uses would not generally be precluded by restoration or mitigation leases.

Many comments also asked about how conservation leases relate to valid existing rights and permitted uses, including grazing, mining, and oil and gas leasing. Restoration and mitigation leases would not disturb existing authorizations, valid existing rights, or State or Tribal land use management. If the proposed activities in a restoration or mitigation lease would conflict with existing authorizations, such as if a specific type of restoration would not be compatible with grazing and the proposed location is already subject to a grazing authorization, then the restoration or mitigation lease could not be issued on those particular lands unless the proposal were modified to eliminate the conflict. While an applicant might propose a lease to help achieve restoration or mitigation outcomes on public lands, the BLM retains discretion as to whether to issue a lease in response to a proposal.

Some commenters raised concerns about the ability of foreign entities to use conservation leases to block development of critical mineral or energy projects on public lands or to obtain conservation leases near military bases or other sensitive government installations. In response to these and other comments on the potential use of conservation leases in ways that would excessively interfere with other uses or to intentionally block development, the BLM clarified that restoration and mitigation leases may only be issued for two discrete purposes: restoration of degraded landscapes or mitigation to offset the impacts of development (6102.4(a)(1)). To specifically address concerns around foreign actors, the BLM also revised the rule to explicitly exclude foreign persons, as that term is defined in 31 CFR 802.221, from being qualified to hold a restoration or mitigation lease. The BLM will rely on its standard lease adjudication practices established in 43 CFR 2920 to determine if a lease applicant meets the preconditions for a qualified lease holder.

The final rule includes various other updates to the language throughout the text of the rule to provide readers with a clearer understanding of the goals and future implementation of the leasing program. For example, the final rule adopts principles for restoration and mitigation that provide additional structure for restoration and mitigation leases. The final rule also refines the BLM's discussion of intact landscapes and restoration priority landscapes, which would support identification of areas for restoration and mitigation leases.

Many commenters recommended that conservation leases should undergo NEPA analysis. A project-level decision to issue a restoration or mitigation lease will comply with NEPA, as is typically the case for Federal actions on public lands, and the BLM will prepare a NEPA analysis to support such project-level decisions when appropriate.

B. Restoration

Commenters provided a wide variety of comments on the topic of restoration. Comments generally related to one of three broad issues: the definition of restoration; the process by which restoration priorities are identified and the use of resource management plans (RMPs) in doing so; and conflicts that can arise in the application of restoration actions.

Several commenters expressed the need for clarifying the definition of restoration and suggested that it should include the concept of returning an area to its natural, native ecological state with several comments recommending that the BLM look to the Society for Ecological Restoration's ''International Principles and Standards for the Practice of Ecological Restoration'' for guidance.

Other commenters requested clarification as to where, how, and when restoration priorities are determined under the rule and called for transparency and public engagement in this process. Some comments also mentioned the use of resource management plans to identify and communicate restoration priorities and expressed concern that including restoration plans in RMPs could complicate and lengthen the RMP adoption or revision process. Other commenters, however, suggested that focusing on creating a 5-year schedule for restoration activities within RMPs is too narrow and proposed looking across watersheds (or subbasins or basins) to identify priorities at the state level, irrespective of RMP boundaries. They stated doing so may assist the BLM in better allocating limited restoration funds. Other comments suggested that restoration plans focus on implementation-level decisions rather than being incorporated into RMPs. One

comment suggested that each BLM district have a map identifying specific areas suitable for restoration measures.

Commenters expressed concerns about the practicalities and potential conflicts with implementing restoration across all BLM-administered lands. Comments discussed how in certain cases, restoration to a reference state may not be feasible or appropriate because the landscape has crossed an ecological threshold and is highly unlikely to be fully restored, or because the resource has high value or function and unique character that cannot be restored or replaced. Several comments discussed the proposed rule's treatment of land health standards in the context of restoration, noting that some restoration actions may not always have positive effects on land health and questioning whether achieving land health standards should be the sole purpose of restoration plans. Commenters raised examples of restoration projects in which the BLM removed pinyon-juniper forest through ecologically damaging practices such as chaining.

In response to comments, the BLM included a new provision within § 6102.3 (''Restoration'') to apply a set of principles to all restoration activities. These principles were largely identified in the draft rule in the context of planning for restoration. In response to comments, these principles now apply to all restoration actions and, among other purposes, seek to ensure that restoration actions directly address the causes of degradation and, importantly, take into consideration the recovery potential of the habitat. These principles will help the BLM target the right restoration actions in the right places, thereby reducing unintended outcomes and increasing the potential for successful restoration.

The principles also ensure that both passive and active management actions are allowable and promoted as restoration activities. Likewise, the definition of restoration has been changed to include explicit mention of both passive and active processes or actions and, in response to comments, include a stated goal of restoration actions to return ecosystems to a ''more natural, native ecological state.''

In response to comments on restoration prioritization and planning, the BLM revised the rule text to provide for the development of restoration plans outside of the RMP revision or amendment process. The final rule requires authorized officers to identify priority landscapes for restoration, consistent with existing, applicable RMP goals and objectives, and to prepare a restoration plan for those priority landscapes. Technical details, including for example geographic scale, for the development of restoration plans can be addressed through agency guidance. Such guidance may also address how to incorporate land health standards into restoration plans and may identify commonly accepted scientific standards within the field of ecological restoration for restoration work.

C. Mitigation

Generally, comments on the mitigation aspects of the rule could be grouped into three categories: the BLM's authority under FLPMA to require mitigation; the policies and practices that govern how the BLM will deploy mitigation, including use of the mitigation hierarchy; and the use of leases, as proposed by the rule, for mitigation purposes.

Many commenters expressed reservations about the BLM's mitigation management approach under the proposed rule, particularly how it might conflict with the multiple use mandate outlined in FLPMA. Critics argued that this could inadvertently prioritize resource preservation at the expense of a more comprehensive management approach, in particular with regard to grazing and recreation. Some commenters posited that the proposed mitigation standards are unlawful and reach beyond the BLM's authority under FLPMA and conflict with other statutory mandates. Other commenters conveyed the reverse, suggesting that the BLM's authority and responsibility to apply the mitigation hierarchy is central to managing for multiple use and sustained yield.

For the reasons discussed in more detail in the Background section above, FLPMA allows the BLM to balance the need for resource conservation alongside other uses as part of managing under principles of multiple use and sustained yield. In turn, FLPMA vests the BLM with broad authority to incorporate appropriate mitigation in its land use planning and to require other users of the public land to avoid, minimize, and compensate for resource impacts, as appropriate, from authorized uses. 43 U.S.C. 1712I, 1732(a)–(b); *see also* M–37039, The Bureau of Land Management's Authority to Address Impacts of its Land Use Authorizations through Mitigation, at 11–22 (Dec. 21, 2016) (reinstated by M–37075 (Apr. 15, 2022)) (''[The] BLM's charge under FLPMA to manage public lands based on principles of multiple use and sustained yield supports use of mitigation. The authority to evaluate and impose mitigation arises out of the broad authority FLPMA vests in the BLM to pursue congressional goals . . . for public lands. The BLM can evaluate and require mitigation through both the land use planning process and site-specific authorizations.'').

There were a number of comments regarding how and where the BLM would deploy mitigation under the proposed rule. Commenters recommended that the BLM amend the rule to require mitigation only to the extent practicable or reasonable and highlighted the need for the BLM to coordinate mitigation with local and State conservation plans. Many commenters were concerned that the use of compensatory mitigation would allow for development in sensitive areas that would otherwise not be allowed, such as ACECs or intact landscapes, and recommended that compensation should not be used to justify activities that could degrade these areas. Some commenters called on the BLM to require that compensatory mitigation measures ensure a net benefit for biodiversity, adhering to established international principles, or avoid the net loss of ecologically intact land. Some commenters narrowed their concern to how compensatory mitigation may specifically impact recreation, which can significantly degrade public resources, and urged that the rule not apply compensatory mitigation requirements to nonprofit organizations, and that ongoing trail use not be subject to such requirements.

In response to these comments, the BLM added mitigation principles to the final rule to provide a framework for how mitigation will be deployed under the rule, including through the mitigation hierarchy and mitigation leasing. The principles are consistent with agency policy and guidance for implementing mitigation, such as developing landscape-scale mitigation strategies, requiring performance criteria and effectiveness monitoring for mitigation programs and projects, and ensuring that compensatory mitigation is durable, additional, timely, and commensurate with adverse impacts. The final rule also confirms that the BLM will adhere to the mitigation hierarchy and that for important, scarce, or sensitive resources, the BLM will apply the mitigation hierarchy in the manner that achieves the maximum benefit to the impacted resource.

Many commenters emphasized the necessity of ensuring that any mitigation credits are based on completed restoration efforts that are actively functioning as habitat for native species impacted by development. These

commenters objected to permitting any proposal to issue credits based on future promises of restoration. Another commenter advocated for third-party mitigation fund holders to facilitate restoration on BLM-managed lands, specifically highlighting the role of private sector mitigation providers, including the ability for private third-party providers to hold mitigation funds. In response to comments, the BLM clarified the types of third-party entities it will allow to hold mitigation funds through a formal agreement. The mitigation fund holder could be a State or local government, if, among other requirements, that entity can demonstrate to the satisfaction of the BLM that it is acting as a fiduciary for the benefit of the mitigation project and site. The section also allows for a mitigation fund holder to be an entity that, among other requirements, qualifies for tax-exempt status and provides evidence it can successfully hold and manage mitigation accounts.

D. Land Health

Comments on aspects of land health in the proposed rule were diverse and focused on: BLM's capacity to evaluate land health across all BLM managed lands, the land health fundamentals, standards, and guidelines; the connection between land health and ecosystem resilience; the application of land health in resource decision-making; and questions about the role of Resource Advisory Councils.

Several commenters conveyed support for the proposal to apply the fundamentals of land health and related standards and guidelines to all BLM-managed public lands and uses, expanding them beyond their original application to rangelands and grazing.

In response to comments, the rule includes streamlined assessment processes applicable at broad spatial scales and a subsequent timeline to review whether such standards remain sufficient.

Commenters provided different recommendations as to how standards and guidelines should be updated. Some suggestions included tying new standards to quantifiable ecologically based performance metrics, specific ecoregions, specific resources, or local ecosystems and conditions. Whatever the outcome of new standards, many commenters conveyed a need for the BLM to provide the public the rationale for new standards and guidelines and clarity as to how they will be applied.

In response to comments, the final rule includes language adopting consistent national land health standards and an allowance to modify national standards to address unique and rare geographic needs.

A few commenters recommended the BLM use flexibility in land health standards to accommodate the diverse array of land uses, especially nonrenewable resources and those with potential surface-disturbing impacts. Various commenters expressed concern that expanding application of land health was unworkable as the BLM cannot meet the current demands for conducting land health analysis under 43 CFR Subpart 4180. To address this, commenters provided several recommendations, including setting appropriate monitoring frequencies, scales, and thresholds, with timelines for corrective actions and milestones. Additionally, commenters supported applying land health at the watershed rather than narrower or smaller scales (allotments, projects, etc.).

In response to comments, the final rule directs the BLM to establish nationally consistent land health standards and indicators and tiers land health standards directly from the fundamentals of land health in order to apply land health standards to a diverse array of land uses. Authorized officers must adopt the national standards and may also adopt geographically specific standards when necessary to evaluate rare or unique habitat or ecosystem types, such as permafrost. To address concerns about the BLM's capacity to apply land health standards to all program areas, the final rule allows field offices to use watershed condition assessments (completed every 10 years) as the baseline for land health evaluations. With watershed condition assessments, land health is assessed at a broad spatial and temporal scale, and may be supplemented by locally specific data.

Some commenters were confused about the role of the Resource Advisory Councils in the development of new standards and guidelines and sought clarification. Although the BLM engages with its Resource Advisory Councils on a wide range of issues, the rule does not require the engagement of Resource Advisory Councils in the development and supplementation of standards and guidelines.

E. Areas of Critical Environmental Concern

Various commenters advocated for strengthening the ACEC relevance and importance criteria, particularly by including habitat connectivity and biodiversity considerations, to ensure the protection of natural, cultural, and scenic resources. Additionally, many comments highlighted the importance of old-growth and mature forests and requested explicit language in the rule to protect and restore old-growth conditions through ACEC designation. The final rule establishes that a historic, cultural, or scenic value; a fish or wildlife resource; or a natural system or process has importance if it contributes to ecosystem resilience, landscape intactness, or habitat connectivity, among other importance criteria. While the final rule does not explicitly contemplate protection of old-growth forest conditions through ACEC designation, the rule specifically enables that management decision by identifying ecosystem resilience and landscape intactness as elements of the ACEC importance criterion. Other provisions in the final rule note that old-growth forests contribute to ecosystem resilience and landscape intactness, such as §§ 6101.2 and 6102.1.

Commenters recommended the final rule mandate more stringent management of designated ACECs in order to ensure protection of relevant and important values identified by the BLM. In response to these comments, the BLM added a management standard to the final rule to ensure ACEC values are appropriately managed for protection and clarified the presumption that a potential ACEC that meets all three criteria of relevance, importance, and needing special management attention will be designated in the land use plan.

Commenters raised concerns about ACEC nominations occurring outside of land use planning processes and that temporary management of potential ACECs would delay other land use authorizations such as renewable energy projects. Questions were raised about the responsibility to notify the public of temporary management decisions and whether temporary management must conform to the current resource management plan. Commenters were also generally interested in ensuring stakeholders and the public have adequate opportunities to participate in ACEC designation decisions.

Generally, the BLM addresses ACECs in the land use planning process. This is because designation of ACECs is intended to be a proactive land management decision to enhance management of important lands and resources. Such decisions should be made while also considering other potential management decisions that may affect those same lands and resources. In rarer situations, the BLM may identify a potential ACEC outside of the planning process and find that it needs special management attention to

ensure proper stewardship of resources and values the agency is charged with managing. In both contexts, the BLM must find that the lands at issue not only possess relevant and important values but also require special management attention. The final element of the standard for ACEC designation means more than finding special management attention will benefit the identified values; rather, it requires a finding that special management is necessary for their stewardship.

Within the land use planning process, the BLM has many tools at its disposal to provide necessary management of resources, ranging from special designation to more narrow management prescriptions. Outside of the planning process, temporary management of a potential ACEC may be the best option for addressing an area that has relevant and important values and requires special management attention to protect them. In those situations, under the final rule and consistent with existing guidance, the BLM may at the agency's discretion implement temporary management to protect the relevant and important values from irreparable damage until the BLM determines whether to designate the potential ACEC through a land use planning process. When implementing temporary management, the BLM would comply with applicable laws and regulations, notify the public, and reevaluate the decision periodically.

The BLM has the authority and the responsibility to mitigate impacts to public land resources from land use authorizations, including by avoiding, minimizing, and offsetting those impacts, independent of ACEC designation status. 43 U.S.C. 1732(a)–(b). Therefore, the BLM does not expect that an ACEC nomination or temporary management process will increase conflict where resources may be impacted by development proposals. Rather, the BLM intends these provisions of the rule to provide a proactive pathway for managing relevant and important values that require special management attention in the limited circumstances in which these values are identified outside of the planning process.

For example, if the BLM is evaluating a proposed development project and has not incorporated consideration of new ACEC designations into the NEPA process for that project, then it is anticipated that the BLM, consistent with existing guidance, would analyze potential impacts to resources and apply the mitigation hierarchy to address those impacts through the NEPA process rather than considering new ACEC designations as part of the ongoing NEPA process. This rule would not require the authorized officer to analyze ACEC nominations during that NEPA process. Rather, the State Director would have the discretion to determine when to evaluate ACEC nominations; the State Director could elect to defer that evaluation to an upcoming planning process. The State Director also would have the discretion to apply temporary management in the area, but only after determining that the area meets the relevance and importance criteria and that special management is necessary to protect the area's relevant and important values from irreparable damage. In other words, the State Director's discretion would include: continuing to process the project by deferring analysis of ACEC nominations; using the data related to ACEC nominations to inform the project analysis; and processing ACEC nominations and incorporating any temporary management into the project evaluation. In all circumstances, the BLM has the discretion to consider ACEC nominations and take steps to implement temporary management for relevant and important values or undertake a plan amendment process to designate new ACECs as outlined in the final rule. The BLM plans to provide additional guidance on situations in which an ACEC nomination overlaps with a pending development project application.

The final rule also emphasizes the ample opportunities for public notice and comment on the ACEC designation process through the resource management planning process, which requires robust public and stakeholder engagement as well as cooperation with local governments and consultation with Tribal governments (43 CFR 1610.2). The final rule confirms that proposed and existing ACECs being addressed by a resource management plan or a plan amendment will be identified in all applicable **Federal Register** Notices and in public outreach materials. The BLM will not, however, be required to continue to produce separate notices specific to ACECs which the BLM found to be duplicative and not in the public interest. The BLM will continue to provide the public with an opportunity to comment on proposed and existing ACECs through the land use planning and associated NEPA requirements for public involvement.

F. Intact Landscapes

Many commenters requested clarity on the rule provisions related to intactness, including how intact landscapes would be identified and managed. Comments recommended that a comprehensive inventory of intact landscapes be part of the land use planning process and that the rule make stronger commitments to prioritizing the conservation and protection of intact landscapes in order to advance the purpose of supporting ecosystem resilience. Additionally, commenters stressed the importance of incorporating community input.

Some commenters emphasized the need to consider other potential uses, such as renewable energy development, and the multiple use management approach when determining whether to manage certain landscapes for intactness. Several comments addressed the importance of acknowledging the human history of intact landscapes and incorporating the concept of cultural landscapes, as well as considering co-stewardship agreements for identified landscapes.

In response to these comments, the BLM updated the rule to clarify that ''landscape intactness'' is part of the resource inventory that is to be maintained and considered in accordance with FLPMA. The final rule also clarifies the land use planning process for this resource, which includes using the intactness inventory to identify and delineate intact landscapes, evaluating alternatives for managing the intact landscapes, and making management decisions for at least some of the intact landscapes or portions of intact landscapes that conserve their intactness. Habitat connectivity and migration corridor data would inform identification and management of intact landscapes, and the BLM would seek opportunities for Tribal co-stewardship in managing and protecting intact landscapes. The BLM anticipates that intact landscapes may vary widely in size and that not every acre of an intact landscape will be managed the same way, as the management focus would be on maintaining function of intact landscapes while facilitating multiple use and supporting sustained yield.

The identification of intact landscapes in the land use planning process would not necessarily preclude land use authorizations that would impair their intactness; rather the BLM would make management decisions for each landscape that would determine allowable uses. Some development could be compatible with management to conserve intactness, and intact landscapes may serve as desirable areas for restoration and mitigation leases. Once an intact landscape has been identified in a land use planning

process, the BLM would consider that resource and analyze potential impacts to it in the planning process and NEPA analysis to evaluate proposed uses, regardless of management decisions for the landscape, consistent with NEPA's requirement that the BLM analyze potential impacts from proposed actions.

G. Grazing

Commenters expressed concern regarding what they considered to be broad and ambiguous interpretations of terms ''conservation,'' ''intact landscapes,'' and ''ecosystem resilience,'' and for the potential for the proposed rule to limit or prohibit consumptive uses, such as grazing. The comments highlighted the need for clarity and consistency in definitions and objectives, suggesting modifications to acknowledge existing uses permitted under FLPMA.

The BLM also received a significant number of comments questioning how conservation leases relate to authorized grazing. Many comments highlighted the need to clarify how proposed conservation leases will interact with grazing management, particularly in cases where grazing may conflict with restoration goals.

In response to comments, the BLM made changes to the leasing section of the final rule. Those changes are summarized in the ''Section-by-Section Discussion of the Final Rule and Revisions from the Proposed Rule'' section and in the ''Conservation Leasing'' section of this discussion. Importantly, the BLM clarified that if proposed activities in a restoration or mitigation lease would conflict with existing authorizations, such as if a specific type of restoration would not be compatible with grazing and the proposed location is already subject to a grazing authorization, then a lease authorizing that type of restoration could not be issued on those particular lands. Additionally, the final rule elevates proposals for leases that can demonstrate collaboration with existing permittees, leaseholders, and adjacent land managers or owners and those that have support from local communities.

Commenters expressed different views as to whether grazing can be used as a land health solution, with some noting that grazing should be used as a land health management tool, while others stated that any use of grazing operations by the BLM to promote land health standards would likely preclude achieving land health goals. Some commenters argued that managed grazing can in fact achieve land health standards and that specific practices, such as targeted grazing, have been used to create fire breaks, manage invasive species, and promote land health. Other commenters argued that livestock grazing is incompatible with restoration and that grazing should be eliminated in areas undergoing restoration. This rule is not establishing or revising regulations governing the BLM's grazing program and does not contemplate using or not using grazing as a land health management tool. As previously discussed, conservation takes many forms on public lands, including in the ways grazing and many other uses are carried out. This rule focuses on conservation as a land use within the multiple use framework and develops the toolbox for conservation use that enables some of the many conservation strategies the agency employs to steward the public lands for multiple use and sustained yield. Grazing as a management tool may fit within these strategies.

Many commenters emphasized the impact that livestock grazing has had on BLM-managed public lands and the need for the BLM to commit to its responsibility under 43 CFR subpart 4180 to monitor achievement of rangeland health standards and manage for proper functioning conditions. One commenter noted that when an allotment fails to meet the standards, changes in grazing practices must be instituted to restore rangeland health. The BLM is not revising subpart 4180 as part of this rulemaking.

H. Recreation

Many commenters emphasized that outdoor recreation is dependent on healthy public lands and waters that provide desirable recreation experiences, which in turn support regional economic growth and help Americans connect with their public lands. They further noted that climate change is having a particular impact on outdoor recreation through drought and catastrophic wildfire, highlighting the need for resilient public lands that can continue to provide recreation opportunities in a changing future. These commenters requested the rule explicitly recognize the tie between landscape health and outdoor recreation and acknowledge that sustainable recreation is compatible with conservation use.

In response to comments, the final rule includes a new objective to: ''Provide for healthy lands and waters that support sustainable outdoor recreation experiences for current and future generations.'' The BLM views sustainable recreation as being compatible with conservation management, including specifically with restoration and mitigation leasing, protection of intact landscapes, management for land health, designation of ACECs, and other principles and management actions provided for in the rule. Furthermore, the BLM anticipates that outdoor recreation would benefit from these conservation measures and would be considered a reason to protect and restore certain landscapes. The additional objective at § 6101.2(g) aims to reflect this intent. The final rule does not specifically address recreation in more detail because the rule is not intended to establish regulations governing recreation use.

Some commenters raised concerns that the rule would reduce the amount of public land available for outdoor recreation. The rule would not change plans, policies, or programs governing recreation activities on public lands; recreation management would still be determined at the local level through land use planning and site-specific recreation management actions such as developed recreation sites, transportation system routes, or trails. As the BLM implements the rule, recreation management decisions will incorporate the objectives and principles set forth in the rule to support landscape health and ecosystem resilience. The rule is not intended to prevent or decrease outdoor recreation use; rather it ensures that recreation on public lands can be managed and grow sustainably while benefiting from the conservation of healthy lands and water.

I. Renewable Energy

Commenters raised concerns about the potential conflicts that could arise between the proposed rule and the BLM's ability to manage and promote renewable energy development. In response to comments, the BLM clarified mitigation language that would allow for renewable energy siting and development, or other kinds of projects, even when that development produces unavoidable impacts. Establishing methods to ensure impacts can be offset and expanding the ability to site compensatory mitigation on public lands through mitigation leases creates more opportunity to permit use while accounting for the unavoidable impacts of such use.

Commenters argued that application of land health standards to renewable energy projects as well as changes to identification and designation of ACECs may have the effect of significantly diminishing the BLM's ability to identify locations where it can permit renewable energy installations and

associated infrastructure. As noted in the discussion of the BLM's response to comments on ACECs, the BLM does not expect that ACEC designations or the potential for temporary management of proposed ACECs will increase conflict where resources may be impacted by development proposals. Rather, the BLM intends these provisions of the rule to provide a proactive pathway for managing relevant and important values that require special management attention, including in the limited circumstances in which these values are identified outside of the planning process.

Lastly, commenters conveyed concern that the proposed rule rested too much decision-making authority on BLM staff over a number of aspects of the rule and that such authority should reside with BLM State Directors. In response, the BLM clarified the responsibilities of Field Managers and State Directors in the ACEC section.

J. Cultural Resource Management

Some comments discussed the connection between cultural values and ecosystem resilience and requested an acknowledgement of this connection and clarity for whether and how the rule would incorporate cultural values or otherwise apply to cultural resource management. Commenters requested that the BLM consider how conservation strategies included in the rule intersect with cultural resources. Specifically, commenters recommended that the rule address American Indian contributions to stewarding the landscapes that the BLM now manages as public lands and may conserve through implementation of this rule, including Indigenous Knowledge and practices handed down over millennia. Commenters also recommended that lands that contain areas of sacred and ceremonial significance to Tribes should not be eligible for conservation leasing unless the purpose of the lease is directly related to those resources.

The BLM is committed to working with Tribes in the management of the public lands, which are the ancestral homelands of American Indian and Alaska Native Tribes. The BLM recognizes Indigenous Peoples have interacted with and stewarded the lands now managed as public lands since time immemorial. This human presence and stewardship continue to influence the lands addressed in the rule, including intact landscapes and ACECs.

Cultural resources can be and often are an essential component of functioning and productive ecosystems, and natural components of ecosystems can also be cultural resources. Some of the BLM's most intact and resilient ecosystems are often also locations with a high probability of containing cultural resources. Cultural and natural values of landscapes co-exist as reasons to protect and manage these landscapes, emphasizing the importance of Indigenous Knowledge and co-stewardship.

Actions and decisions aimed at restoring, maintaining, and conserving ecosystems and landscapes may inadvertently result in impacts to cultural resources. All such undertakings will be subject to section 106 of the NHPA, as well as NEPA. Through the section 106 process, the BLM will, in consultation with Tribes, State and Tribal Historic Preservation Officers, and interested parties, identify, evaluate, and resolve any adverse effects on historic properties. Any potential adverse effects to historic properties will be avoided, minimized, or otherwise mitigated in accordance with law, regulation, and policy. Effects to cultural resources that are not identified as historic properties under the NHPA will be considered and managed through land use plans and the NEPA process. In addition, the BLM will strive to consider and implement the new Best Practices Guide for Federal Agencies Regarding Tribal and Native Hawaiian Sacred Sites.[16]

K. Mature and Old-Growth Forests

Many comments were received emphasizing the need to protect old-growth and mature forests as part of meeting the rule's stated purpose of supporting ecosystem resilience on public lands. Commenters recommended adding provisions to the rule to establish emphasis areas for old-growth and mature forests, limit or prohibit tree cutting on BLM-managed lands, facilitate designation of old-growth forests as ACECs, and focus on climate sustainable logging. Commenters highlighted the scientific and social values of old-growth and mature forests and requested explicit language in the rule to protect these valuable ecosystems consistent with Executive Order 14072.

Executive Order 14072, *Strengthening the Nation's Forests, Communities, and Local Economies,* calls for defining, identifying, and inventorying the nation's old and mature forests and stewarding them for future generations to provide clean air and water, sustain plant and animal life, and respect their special importance to Tribal Nations, consistent with applicable law. The BLM is working with the U.S. Forest Service to implement the provisions in Executive Order 14072 related to mature and old-growth forests. In April 2023, the BLM and U.S. Forest Service released a definition framework and initial inventory of mature and old-growth forests on Federal lands, and the agencies are now analyzing threats to those forests pursuant to the Executive Order. The initial inventory identified 8.3 million acres of old-growth and 12.7 million acres of mature forest on BLM-administered lands, the majority of which are pinyon and juniper woodlands. Mature and old-growth forests and woodlands contribute to ecosystem resilience by providing wildlife habitat, clean water, carbon storage, and landscape intactness. They also have important social and cultural values.

The final rule facilitates conservation of BLM-managed forests and woodlands through multiple provisions, including those related to identification and protection of intact landscapes; conservation tools to protect certain lands and resources through land use planning; avoiding authorizing uses of the public lands that permanently impair ecosystem resilience; and co-stewardship opportunities with Tribes. In order to clarify this intent, the final rule specifically identifies conservation of old-growth forests within the objectives of the regulation. Because this is a procedural rule, establishing emphasis areas or other site-specific protections for old-growth forests is outside the scope of the rule.

L. Wild Horses and Burros

The BLM received comments on using the rule to change wild horse and burro management on public lands. Commenters recommended classifying wild horses and burros as a use of public lands, requiring the BLM to show that removal of livestock could not achieve the same objective as removal of wild horses and burros, restricting livestock grazing to reduce methane emissions and provide more forage for wild horses and burros, and allowing restoration and mitigation leases to be used to protect wild horse and burro habitat.

Management of wild horses and burros is governed by the Wild Free-Roaming Horses and Burros Act of 1971, as amended, and its implementing regulations (43 CFR part 4700). Wild horses and burros are managed in the

[16] Working Group of the Memorandum of Understanding Regarding Interagency Coordination and Collaboration for the Protection of Indigenous Sacred Sites (2023), *https://www.bia.gov/sites/default/files/media_document/sacred_sites_guide_508_2023-1205.pdf* (providing guidance on implementation of Executive Orders 13175, 13007, and 14096, and related policies).

areas where they are found, and decisions on herd management are made through the BLM's land use planning process. This rule does not authorize or mandate decisions to manage wild horses and burros. The rule does require the use of high-quality information that promotes reasoned, fact-based agency decisions in making land use allocations and other land use authorizations, including grazing authorizations. Restoration and mitigation leases are narrowly defined tools for restoring degraded landscapes or compensating for impacts of development and are not appropriate mechanisms for protecting wild horse and burro habitat.

M. NEPA Compliance for the Rule

A number of comments objected to the BLM's intent to rely on a categorical exclusion to comply with NEPA and called on the BLM to instead prepare an environmental assessment or environmental impact statement under NEPA.

The BLM has determined that the categorical exclusion set out at 43 CFR 46.210(i) applies to this rulemaking. That provision excludes from NEPA analysis and review actions that are ''of an administrative, financial, legal, technical, or procedural nature; or whose environmental effects are too broad, speculative, or conjectural to lend themselves to meaningful analysis and will later be subject to the NEPA process, either collectively or case-by-case.'' That categorical exclusion applies because the rule sets out a framework but is not self-executing in that it does not itself make substantive changes on the ground and will not (absent future decisions that implement the rule) restrict the BLM's discretion to undertake or authorize future on-the-ground action; thus, the rule is administrative or procedural in nature. Any future actions, including both land use planning and individual project-level decisions, including decisions to issue a restoration or mitigation lease, will be subject to the appropriate level of NEPA review at the time of that decision. Where the BLM will undertake such actions, which of the various tools provided in this rule it will use when doing so, and the particular methods and activities it will employ are unknown at this time, making the environmental effects associated with those future actions too speculative or conjectural to meaningfully evaluate now. The BLM has also determined that none of the extraordinary circumstances identified at 43 CFR 46.215 applies to this rulemaking.

N. Inventory, Assessment, and Monitoring

Public comments recommended that monitoring data and analyses should be made public to promote transparent decision processes. Commenters recommended emphasis on particular monitoring approaches and discouraged use of other approaches and requested more details on the monitoring implementation process and how it would tie to decision-making across different types of decisions. Commenters also recommended adding a process for monitoring prioritization.

Many commenters asked for clarification on watershed condition classifications, renamed ''watershed condition assessments'' in the final rule, including who would complete them and how often, what data they would include, whether outside partners would be engaged, and how they would tie to decision-making. Many recommended a nationally consistent process for completing watershed condition assessments in order to ensure that they were efficient and effective. Some asked how watershed condition assessments would interact with and inform the BLM land health process. Several questioned whether additional assessments were needed.

In response to public comments, the final rule clarifies that a focus of the rule is monitoring of infrastructure and renewable resources. It states that inventory, monitoring, and assessment information will be publicly available (currently, at the BLM Geospatial Business Platform Hub, *https://gbp-blm-egis.hub.arcgis.com/*), consistent with the Open Government Data Act, section 202(b). The final rule defines watershed condition assessments and specifies that they will be created using a consistent process and standardized data. The final rule recommends that high-quality information, including monitoring and watershed condition assessments, be used to inform many different types of decisions in the rule. Further details regarding inventory, assessment, and monitoring, including watershed condition assessments, may be addressed in implementation guidance.

Some comments questioned whether the monitoring provisions of the rule apply to cultural and paleontological resources. As stated in the Authority section of the final rule, implementation of the rule will be subject to and must be undertaken consistent with all applicable laws, which would include the NHPA and the PRPA.

O. Economic Analysis and Compliance With the Regulatory Flexibility Act

Many commenters insisted that the Regulatory Flexibility Act (RFA) required the BLM to prepare an initial regulatory flexibility analysis and, by extension, that this final rule would require a final regulatory flexibility analysis. Those commenters requested specific documentation and details of the economic impact on small businesses and other entities. Commenters stated that the BLM's certification that the rule would not have a significant economic impact on a substantial number of small entities lacked a proper factual basis.

The BLM disagrees with commenters' assertion that the RFA required for the proposed rule and so requires for this final rule a regulatory flexibility analysis. The BLM certified at the proposed rule stage and certifies again in promulgating this final rule that the rule will not have a significant economic impact on a substantial number of small entities. Under the Small Business Administration's (SBA) Guide for Federal Agencies to Comply with the Regulatory Flexibility Act, when certifying that a regulatory flexibility analysis is not required, the ''certification should contain a description of the number of affected entities and the size of the economic impacts and why either the number of entities or the size of the impacts justifies the certification.'' Here, the BLM has undertaken an economic threshold analysis and concluded that the magnitude of the impact on any individual or group, including small entities, is expected to be negligible (Economic Threshold Analysis). In support of this determination, the BLM followed SBA's certification checklist items.

The SBA's guidelines provide, ''The RFA does not define 'significant impact' or 'substantial number,' and it is the agencies' discretion on where to set these thresholds on a rule-to-rule basis based on their judgment.'' The BLM exercised its discretion to conclude that an initial regulatory flexibility analysis was not required for the proposed rule and that a final regulatory flexibility analysis is not required now.

V. Procedural Matters

Regulatory Planning and Review (Executive Orders 12866, 13563 and 14094)

Executive Order (''E.O.'') 12866, ''Regulatory Planning and Review,'' as supplemented and reaffirmed by E.O. 13563, ''Improving Regulation and Regulatory Review,'' 76 FR 3821 (Jan.

21, 2011) and amended by E.O. 14094, ''Modernizing Regulatory Review,'' 88 FR 21879 (April 11, 2023), requires agencies, to the extent permitted by law, to (1) propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public. E.O. 12866, as amended by E.O. 14094, provides that the Office of Information and Regulatory Affairs (''OIRA'') in the Office of Management and Budget (''OMB'') will review all significant rules. Section 6(a) of E.O. 12866 also requires agencies to submit ''significant regulatory actions'' to OIRA for review. OIRA has determined that this final regulatory action constitutes a ''significant regulatory action'' within the scope of E.O. 12866.

E.O. 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the Nation's regulatory system to promote predictability, reduce uncertainty, and use the best, most innovative, and least burdensome tools for achieving regulatory ends. The E.O. directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rule making process must allow for public participation and an open exchange of ideas. The BLM has developed this rule in a manner consistent with these requirements.

Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) generally requires that Federal agencies prepare a regulatory flexibility analysis for rules subject to the ''notice-and-comment'' rulemaking requirements found in the Administrative Procedure Act (5 U.S.C. 551 *et seq.*), if the rule would have a significant economic impact, whether detrimental or beneficial, on a substantial number of small entities. See 5 U.S.C. 601–612. Congress enacted the RFA to ensure that government regulations do not unnecessarily or disproportionately burden small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

For the purpose of conducting its review pursuant to the RFA, the BLM certifies that the rule would not have a ''significant economic impact on a substantial number of small entities,'' as that phrase is used in 5 U.S.C. 605. The rule does not affect any existing use of public lands, nor does it impose restrictions on future use. The rule modifies BLM decision-making processes and does not directly regulate any industry, but it may affect industries related to environmental restoration or mitigation activity or other sectors that rely on public lands management. The BLM does not expect those impacts to be significant. See the Economic Analysis, *Potential Impact on Small Entities,* for more information.

Congressional Review Act (CRA)

Pursuant to subtitle E of the Small Business Regulatory Enforcement Fairness Act of 1996 (also known as the Congressional Review Act), the Office of Information and Regulatory Affairs has determined that this rule does not meet the criteria set forth in 5 U.S.C. 804(2). This rule:

a. Does not have an annual effect on the economy of $100 million or more. The BLM did not estimate the annual benefits that this rule would provide to the economy. Please see the Economic Analysis for this rule for a more detailed discussion.

b. Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions. The rule would benefit small businesses by streamlining the BLM's processes.

c. Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises. The rule would not have adverse effects on any of these criteria.

Unfunded Mandates Reform Act (UMRA)

This rule does not impose an unfunded mandate on State, local, or Tribal governments, or the private sector of more than $100 million per year. The rule does not have a significant or unique effect on State, local, or tribal governments, or the private sector. Under the Unfunded Mandates Reform Act (UMRA) (2 U.S.C. 1531 *et seq.*), agencies must prepare a written statement about benefits and costs prior to issuing a proposed or final rule that may result in aggregate expenditure by State, local, and tribal governments, or the private sector, of $100 million or more in any 1 year.

This rule is not subject to those requirements of the UMRA. The rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or to the private sector in any one year. The rule would not significantly or uniquely affect small governments. A statement containing the information required by the UMRA is not required.

Government Actions and Interference With Constitutionally Protected Property Rights Takings (E.O 12630)

This rule does not effect a taking of private property or otherwise have taking implications under E.O. 12630. Section 2(a) of E.O. 12630 identifies policies that do not have takings implications, such as those that abolish regulations, discontinue governmental programs, or modify regulations in a manner that lessens interference with the use of private property. The rule will not interfere with private property. A takings implication assessment is not required.

Federalism (E.O 13132)

Under the criteria in Section 1 of E.O. 13132, this rule does not have sufficient federalism implications to warrant the preparation of a federalism summary impact statement. It does not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

The BLM received broad and general comments suggesting that E.O. 13132 requires preparation of a federalism summary impact statement with respect to this rule. In particular, some comments raised concerns that conservation leases (now titled

restoration and mitigation leases) could infringe on state and local authority. Executive Order 13132 generally prohibits Federal agencies from promulgating rules that might have a substantial direct effect on states or local governments, on the relationship between Federal and State governments, or on the distribution of power and responsibilities among the various levels of government, without meeting certain conditions, such as consulting with elected State and local government officials early in the process. In particular, administrative rules may not create substantial direct compliance costs for state or local governments that are not otherwise required by statute and may not expressly or impliedly preempt state law without Federal agencies undertaking additional processes. This rule will inform the BLM's management approach on federal land in the several states where BLM manages public land, but nothing in the rule, including its provisions for restoration and mitigation leasing, preempts state law or requires state or local governments to comply with specific provisions. Nor does the rule modify let alone reduce the role, under FLPMA, of state and local governments in land use planning. As a result, a federalism summary impact statement is not required.

Civil Justice Reform (E.O 12988)

This rule complies with the requirements of E.O. 12988. Specifically, this rule:

a. Meets the criteria of Section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

b. Meets the criteria of Section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

Consultation and Coordination With Indian Tribes (E.O 13175 and Departmental Policy)

The Department of the Interior (DOI) endeavors to maintain and strengthen its government-to-government relationship with Indian Tribes through a commitment to consultation with Indian Tribes and recognition of their right to self-governance and tribal sovereignty. We have evaluated this rule under the DOI's consultation policy and under the criteria in E.O. 13175 and have determined that the rule has tribal implications.

In conformance with the Secretary's policy on Tribal consultation, the BLM sent letters to all Tribes at the beginning of the rulemaking process informing them of the proposed rule and inviting them to engage with BLM on their thoughts and concerns. The BLM received input from Tribal governments, Alaska Native Corporations, and Tribal entities in comments on the proposed rule, as well as in other meetings that included a broader range of topics, and incorporated their input in drafting the final rule. Consistent with the DOI's consultation policy (52 Departmental Manual 4) and the criteria in E.O. 13175, the BLM will continue to consult with federally recognized Indian Tribes on any proposal that may have Tribal implications.

Paperwork Reduction Act

The Paperwork Reduction Act (PRA) (44 U.S.C. 3501–3521) generally provides that an agency may not conduct or sponsor, and notwithstanding any other provision of law a person is not required to respond to, a collection of information, unless it displays a currently valid Office of Management and Budget (OMB) control number. This rule contains information collection requirements that are subject to review by the OMB under the PRA. Collections of information include any request or requirement that persons obtain, maintain, retain, or report information to an agency, or disclose information to a third party or to the public (44 U.S.C. 3502(3) and 5 CFR 1320.3(c)).

OMB has generally approved the existing information collection requirements contained in the BLM's regulations contained in 43 CFR subpart 1610 under OMB Control Number 1004–0212. The final rule would not result in any new or revised information collection requirements that are currently approved under that OMB Control Number.

For the reasons set out in the preamble, the BLM is amending 43 CFR by creating Part 6100 which would result in new information collection requirements that require approval by OMB. The information collection requirement contained in part 6100 will allow the BLM to issue a restoration or mitigation lease to qualified entities for the purpose of restoring degraded land or resources, or mitigation to offset the impacts of other land use authorizations. The new information collection requirements contained in the final rule are discussed below.

New Information Collection Requirements

§ 6102.4(b) and (c)—Restoration and Mitigation Leasing: Applications for restoration or mitigation leases shall be filed with the Bureau of Land Management office having jurisdiction over the public lands covered by the application. Applications for restoration or mitigation leases shall include a restoration or mitigation development plan which includes sufficient detail to enable the authorized officer to evaluate the feasibility, impacts, benefits, costs, threats to public health and safety, collaborative efforts, and conformance with BLM plans, programs, and policies, including compatibility with other uses. The development plan shall include but not be limited to:

- Results from available assessments, inventory and monitoring efforts, or other high-quality information that identify the current conditions of the site(s) of the proposed restoration or mitigation action;
- The desired future condition of the proposed lease area including clear goals, objectives, and measurable performance criteria needed to achieve the objectives;
- Justification for passive restoration or mitigation if proposed;
- A description of all facilities for which authorization is sought, including access needs and any other special types of authorizations that may be needed;
- A map of sufficient scale to allow the required information to be legible as well as a legal description of primary and alternative project locations;
- Justification of the total acres proposed for the restoration or mitigation lease;
- A schedule for restoration activities, if applicable; and
- Information on outreach conducted or to be conducted with existing permittees, lease holders, adjacent land managers or owners, and other interested parties.

§ 6102.4(c)(4)—Restoration and Mitigation Leasing (additional information): After review of the restoration or mitigation development plan, the authorized officer may require the applicant to provide additional high-quality information, if such information is necessary for the BLM to decide whether to issue, issue with modification, or deny the proposed lease. An application for the use of public lands may require documentation or proof of application for additional private, State, local or other Federal agency licenses, permits, easements, certificates, or other approval documents. The authorized officer may require evidence that the applicant has or prior to commencement of lease activities will have the technical and financial capability to operate, maintain, and terminate the authorized lease activities.

§ 6102.4(e)—Restoration and Mitigation Leasing/Monitoring Plan: If approved, the lease holder shall provide a monitoring plan that describes how the terms and conditions of the lease will be applied, the monitoring methodology and frequency, measurable criteria, and adaptive management triggers.

§ 6102.4(e)(1)—Restoration and Mitigation Leasing/Annual Report: The lease holder shall provide a lease activity report annually and at the end of the lease period. At a minimum, the report shall describe:

- the restoration or mitigation activities taken as of the time of the report;
- any barriers to meeting the stated purpose of the lease;
- proposed steps to resolve any identified barriers; and
- monitoring information and data that meet BLM methodology requirements and data standards (see § 6103.2(c)).

§ 6102.4.1(d)(3)—Termination and Suspension of Restoration and Mitigation Leases: Upon determination that there is noncompliance with the terms and conditions of a restoration or mitigation lease which adversely affects land or public health or safety, or impacts ecosystem resilience, the authorized officer shall issue an immediate temporary suspension. Any time after an order of suspension has been issued, the holder may file with the authorized officer a request for permission to resume. The request shall be in writing and shall contain a statement of the facts supporting the request.

§ 6102.4.2(a)—Bonding for Restoration and Mitigation Leases: Prior to the commencement of surface-disturbing activities, the authorized officer may require the restoration or mitigation lease holder to submit a reclamation, decommission, or performance bond conditioned upon compliance with all the terms and conditions of the lease covered by the bond. For mitigation leases, the lease holder will usually be required to provide letters of credit or establish an escrow account for the full amount needed to ensure the development plan meets all performance criteria.

§ 6102.5.1(d)—Mitigation—Approval of third parties as mitigation fund holders: § 6102.5.1(d) would allow in certain limited circumstances authorized officers to approve third parties as mitigation fund holders to establish mitigation accounts for use by entities granted land use authorizations by the BLM. The authorized officer will approve the use of a mitigation account by a permittee only if a mitigation fund holder has a formal agreement with the BLM.

§ 6102.5.1(e)—Mitigation—Approval of third parties as mitigation fund holders/State and local government agencies: State and local government agencies are limited in their ability to accept, manage, and disburse funds for the purpose outlined in § 6102.5.1 and generally should not be approved by the BLM to hold mitigation funds for compensatory mitigation sites on public or private lands. An exception may be made where a government agency is able to demonstrate, to the satisfaction of the BLM, that they are acting as a fiduciary for the benefit of the mitigation project or site, essentially as if they are a third party, and can show that they have the authority and perform the duties described in § 6102.5.1.

Information Collection Changes From Proposed to Final Rule:

The BLM introduced the following information collection requirements that were not in the proposed rule:

- Restoration and Mitigation Leasing/Monitoring Plan—43 CFR 6102.4(e);
- Restoration and Mitigation Leasing/Annual Report—43 CFR 6102.4(e)(1); and
- Mitigation/Approval third parties as mitigation fund holders/Annual Fiscal Reports—43 CFR 6102.5–1(e).

These ICs are necessary to provide monitoring mechanisms to help the BLM assure that we are achieving the desired outcomes of the restoration and mitigation plans.

The information collection requirements contained in this rule are needed to ensure that accountability through restoration monitoring and tracking is carried out effectively and that project goals are being met. The estimated annual information collection burdens for this rule are outlined below:

Collection of information	Number of responses	Time per response (hours)	Total hours
Restoration and Mitigation Leasing/Restoration or Mitigation Development Plan—43 CFR 6102.4(b) and (c)	10	10	100
Restoration and Mitigation Leasing/Additional Information 43 CFR 6102.4(c)(5)	8	25	200
Restoration and Mitigation Leasing/Monitoring Plan—43 CFR 6102.4(e)	9	5	45
Restoration and Mitigation Leasing/Annual Report—43 CFR 6102.4(e)(1)	9	2	18
Termination and Suspension of Restoration and Mitigation Leases/written request to resume or suspended activity—43 CFR 6102.4–1(d)(3)	1	240	240
Bonding for Restoration and Mitigation Leases—43 CFR 6102.4–2(a)	10	80	800
Mitigation/Approval third parties as mitigation fund holders—43 CFR 6102.5–1(e)	4	5	20
Mitigation/Approval third parties as mitigation fund holders—43 CFR 6102.5–1(g)	4	5	20
Mitigation/Approval third parties as mitigation fund holders/Annual Fiscal Reports—43 CFR 6102.5–1(e)	4	2	8
Mitigation/Approval third parties as mitigation fund holders/Annual Fiscal Reports—43 CFR 6102.5–1(e)	4	2	8

Information Collection Summary:

Title of Collection: Ecosystem Resilience (43 CFR part 6100).

OMB Control Number: 1004–0218.

Form Number: None.

Type of Review: New collection of information.

Respondents/Affected Public: Private sector businesses; Not-for-profit organizations; and State, local, or Tribal governments.

Respondent's Obligation: Required to Obtain or Retain a Benefit.

Frequency of Collection: On occasion; Annual.

Estimated Completion Time per Response: Varies from 5 hours to 240 hours per response, depending on activity.

Number of Respondents: 63.

Annual Responses: 63.

Annual Burden Hours: 1,459.

Annual Burden Cost: $0.

If you want to comment on the information-collection requirements in this rule, please send your comments and suggestions on this information-collection within 30 days of publication of this final rule in the **Federal Register**

to OMB by going to *www.reginfo.gov.* Click on the link, ''Currently under Review—Open for Public Comments.''

National Environmental Policy Act (NEPA)

This rule is excluded from review under the National Environmental Policy Act under Department Categorical Exclusion (CX) at 43 CFR 46.210(i). This CX covers policies, directives, regulations, and guidelines that are of an administrative, financial, legal, technical, or procedural nature or whose environmental effects are too broad, speculative, or conjectural to lend themselves to meaningful analysis and will later be subject to the NEPA process, either collectively or case-by-case. The BLM has documented this CX's applicability to this action and posted it for public review here in docket BLM–2023–0001 on regulations.gov.

Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use (E.O. 13211)

Federal agencies must prepare and submit to OMB a Statement of Energy Effects (SEE) for any significant energy action. A ''significant energy action'' is defined as any action by an agency that: (1) Is a significant regulatory action under Executive Order 12866, or any successor order, and is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) Is designated by the Administrator of OIRA as a significant energy action. This rule is a significant action under Executive Order 12866; however, this rule does not affect energy supply, distribution, or use, and OIRA has not designated it a significant energy action. Therefore, it is not a significant energy action under E.O. 13211, and a SEE is not required.

The BLM received many comments on its determination that this rule is not a significant energy action. Commenters stated that the proposed rule, particularly the regulations pertaining to ACECs and the establishment of a restoration and mitigation leasing program (conservation leasing in the proposed rule), would displace oil and gas production and mining for critical minerals on public lands. Commenters also expressed concern that ACEC designation and restoration and mitigation leases could preclude energy rights of way for transmission lines. Commenters requested more information on how the BLM determined that this rulemaking would not have a significant adverse effect on energy supply, distribution, or use, and specifically requested the BLM complete a SEE for this rulemaking.

The BLM disagrees that the rule would adversely impact the supply, distribution, or use of energy. No part of the rule would preclude the development or transmission of energy on or across public lands without due consideration of multiple use and sustained yield principles through BLM's existing decision-making processes, including the required public engagement. Restoration and mitigation leases may not be issued in areas where an existing and otherwise incompatible use is occurring; thus, they would not displace existing mineral leases or mining claims. Restoration and mitigation leases are a narrow tool which may only be issued to restore degraded landscapes or to offset impacts of other land use authorizations; they may not be used to ''block'' development of mineral resources on lands allocated to such use in the governing Resource Management Plan. In many cases, these leases will facilitate the development of energy on public lands by providing an avenue for developers to satisfy obligations to offset the impacts of energy development through compensatory mitigation.

The revised regulations for ACEC designation will not adversely affect the supply, distribution or use of energy on public lands. FLPMA has required that the BLM prioritize the designation and protection of ACECs since 1976, and the final rule does not change that requirement or the overall process and parameters for their designation and management. The BLM does not expect that ACEC designations or the potential for temporary management of proposed ACECs will increase conflict where resources may be impacted by development proposals. Rather, the BLM intends these provisions of the rule to provide a proactive pathway for managing relevant and important values that require special management attention in the limited circumstances in which these values are identified outside of the planning process. See Section IV, Response to Comments, part E., Areas of Critical Environmental Concern, for more information.

Clarity of This Regulation (Executive Orders 12866, 12988 and 13563)

We are required by Executive Orders 12866 (section 1(b)(12)), 12988 (section 3(b)(1)(B)), and 13563 (section 1(a)), and by the Presidential Memorandum of June 1, 1988, to write all rules in plain language. This means that each rule must: a) Be logically organized; b) Use the active voice to address readers directly; c) Use common, everyday words and clear language rather than jargon; d) Be divided into short sections and sentences; and e) Use lists and tables wherever possible.

Authors

The principal authors of this rule are: Patricia Johnston, BLM Division of Wildlife Conservation, Aquatics, and Environmental Protection; Darrin King, BLM Division of Regulatory Affairs; Chandra Little, BLM Division of Regulatory Affairs, assisted by the DOI Office of the Solicitor.

The action taken herein is pursuant to an existing delegation of authority.

List of Subjects in 43 CFR Part 1600

Administrative practice and procedure, Coal, Conservation, Environmental impact statements, Environmental protection, Intergovernmental relations, Preservation, Public lands.

This action by the Principal Deputy Assistant Secretary is taken pursuant to an existing delegation of authority.

Steven H. Feldgus,

Deputy Assistant Secretary for Land and Minerals Management.

Accordingly, for the reasons set out in the preamble, the Bureau of Land Management amends 43 CFR Chapter II as set forth below:

PART 1600—PLANNING, PROGRAMMING, BUDGETING

■ 1. The authority citation for part 1600 continues to read as follows:

Authority: 43 U.S.C. 1711–1712.

■ 2. Revise § 1610.7–2 to read as follows:

§ 1610.7–2 Designation of areas of critical environmental concern.

(a) An area of critical environmental concern (ACEC) designation is the principal BLM designation for public lands where special management is required to protect and prevent irreparable damage to important historic, cultural, or scenic values; fish or wildlife resources; or natural systems or processes or to protect life and safety from natural hazards. The BLM designates ACECs when issuing a decision to approve a resource management plan, plan revision, or plan amendment. ACECs shall be managed to protect the relevant and important values for which they are designated.

(b) In the land use planning process, authorized officers must identify, evaluate, and give priority to areas that have potential for designation and management as ACECs. Identification, evaluation, and priority management of

ACECs shall be considered during the development and revision of resource management plans and during amendments to resource management plans when such action falls within the scope of the amendment (*see* §§ 1610.4–1 through 1610.4–9). Proposed and existing ACECs that will be addressed by a resource management plan, plan revision, or plan amendment will be identified in all public notices required by this part (*see, e.g.,* § 1610.2).

(c) The authorized officer must facilitate the identification of eligible ACECs early in the land use planning process by:

(1) Analyzing inventory, assessment, and monitoring data to determine whether there are areas containing important historic, cultural, or scenic values; fish or wildlife resources; natural systems or processes; or natural hazards potentially impacting life and safety that are eligible for designation;

(2) Reevaluating existing ACECs in order to determine if the relevant and important values are still present and special management attention is still necessary; and

(3) Seeking nominations for ACECs, during public scoping, from the public, State and local governments, Indian Tribes, and other Federal agencies (*see* §§ 1610.2(c), 1602.5(b)(4) through (6)).

(d) To be designated as an ACEC, an area must meet the following criteria:

(1) *Relevance.* The area contains important historic, cultural, or scenic values; fish or wildlife resources; natural systems or processes; or natural hazards potentially impacting life and safety.

(2) *Importance.* A historic, cultural, or scenic value; a fish or wildlife resource; a natural system or process; or a natural hazard potentially impacting life and safety has importance if it has qualities of special worth, consequence, meaning, distinctiveness, or cause for concern; national or more than local importance, subsistence value, or regional contribution of a resource, value, system, or process; or contributes to ecosystem resilience, landscape intactness, or habitat connectivity. A natural hazard can be important if it is a significant threat to human life and safety.

(3) *Special management attention.* The important historic, cultural, or scenic values; fish or wildlife resources; natural systems or processes; or natural hazards potentially impacting life and safety require special management attention. ''Special management attention'' means management prescriptions that:

(i) Protect and prevent irreparable damage to the relevant and important values, or that protect life and safety from natural hazards; and

(ii) Would not be prescribed if the relevant and important values were not present. In this context, ''irreparable damage'' means harm to a value, resource, system, or process that substantially diminishes the relevance or importance of that value, resource, system, or process in such a way that recovery of the value, resource, system, or process to the extent necessary to restore its prior relevance or importance is impossible.

(e) The authorized officer may designate an ACEC research natural area if the area:

(1) Meets all of the criteria identified in § 1610.7–2(d)(1) through (3); and

(2) Is consistent with one or more of the primary purposes found at § 8223.0–5 of this chapter. A designated ACEC research natural area will be subject to the use restrictions at § 8223.1 of this title in addition to the special management attention prescribed by the authorized officer through land use planning.

(f) The boundaries of proposed ACECs shall be identified for public lands, as appropriate, to encompass the relevant and important values and geographic extent of the special management attention needed to provide protection.

(g) During a planning process, the planning documents must analyze in detail any proposed ACEC that has relevant and important values. Where the BLM has received ACEC proposals that do not have relevant and important values, the agency is not required to review those proposals in detail in planning documents. Through land use planning, the BLM will evaluate the need for special management attention to protect the relevant and important values, which could include other allocations and designations being considered, in order to provide for informed decision-making on the trade-offs associated with ACEC designation.

(h) The approved resource management plan, plan revision, or plan amendment shall list all designated ACECs, identify their relevant and important values, and include the special management attention, including management prescriptions for other uses, identified for each designated ACEC.

(i) ACEC nominations typically should be evaluated during a planning process. If a nomination for an ACEC is received outside of the planning process, the following provisions apply.

(1) The State Director will evaluate whether the relevant, important, and special management criteria identified in paragraph (d) of this section are met. The State Director will determine the appropriate time to complete this analysis. If the criteria identified in paragraph (d) of this section are met, then the State Director shall, at their discretion, either:

(i) Initiate a land use planning process; or

(ii) Provide temporary management consistent with the applicable resource management plan to protect the relevant and important values from irreparable damage. Any temporary management that is implemented would be in effect until the BLM either completes a land use planning process to determine whether to designate the area as an ACEC or, through periodic evaluation, finds designation is no longer necessary. The BLM will publish a public notice if temporary management is implemented.

(2) The State Director may defer evaluating the nomination to an upcoming planning process.

(j) The State Director shall:

(1) Determine which ACECs to designate based on:

(i) The presumption that all areas found to require special management attention will be designated;

(ii) The value of other resource uses in the area;

(iii) The feasibility of managing the designation; and

(iv) The relationship to other types of designations and protective management available.

(2) In the decision document for the resource management plan or plan amendment, provide a justification and rationale for both ACEC designation decisions and decisions not to designate a proposed ACEC.

(3) Administer designated ACECs in a manner that conserves, protects, and enhances the relevant and important values and only allow casual use or uses that will ensure the protection of the relevant and important values. This paragraph (j)(3) does not apply to those ACECs designated for natural hazards potentially impacting life and safety.

(4) Prioritize acquisition of inholdings within ACECs and adjacent or connecting lands identified as holding relevant and important values related to the designated ACEC.

(k) The State Director, through the land use planning process, may remove the designation of an ACEC, in whole or in part, only when:

(1) The State Director finds that special management attention is not needed because another legally enforceable mechanism provides an equal or greater level of protection; or

(2) The State Director finds that the relevant and important values are no longer present, cannot be recovered, or

have recovered to the point where special management is no longer necessary. The findings must be supported by data or documented changes on the ground.

(l) As used in this section, the terms casual use, conservation, ecosystem resilience, intactness, landscape, monitoring, protection, and restoration have the same meanings as in § 6101.4 of this chapter.

■ 3. Add part 6100 to read as follows:

PART 6100—ECOSYSTEM RESILIENCE

Subpart 6101—General Information

Sec.
6101.1 Purpose.
6101.2 Objectives.
6101.3 Authority.
6101.4 Definitions.
6101.5 Principles for Ecosystem Resilience.

Subpart 6102—Conservation Use to Achieve Ecosystem Resilience

Sec.
6102.1 Protection of Landscape Intactness.
6102.2 Management to Protect Intact Landscapes.
6102.3 Restoration.
6102.3.1 Restoration Prioritization and Planning.
6102.4 Restoration and Mitigation Leasing.
6102.4.1 Termination and Suspension of Restoration and Mitigation Leases.
6102.4.2 Bonding for Restoration and Mitigation Leases.
6102.5 Management Actions for Ecosystem Resilience.
6102.5.1 Mitigation.

Subpart 6103—Managing Land Health to Achieve Ecosystem Resilience

Sec.
6103.1 Land Health Standards.
6103.1.1 Management for Land Health.
6103.1.2 Land Health Evaluations and Determinations.
6103.2 Inventory, Assessment and Monitoring.

Authority: 16 U.S.C. 7202; 43 U.S.C. 1701 *et seq.*

PART 6100—ECOSYSTEM RESILIENCE

Subpart 6101—General Information

§ 6101.1 Purpose.

The BLM's management of public lands on the basis of multiple use and sustained yield relies on healthy landscapes and resilient ecosystems. The purpose of this part is to promote the use of conservation to ensure ecosystem resilience and prevent permanent impairment or unnecessary or undue degradation of public lands. This part discusses the use of protection and restoration actions, as well as tools such as watershed condition assessments, land health evaluations, inventory, assessment, and monitoring.

§ 6101.2 Objectives.

The objectives of this part are to:

(a) Achieve and maintain ecosystem resilience when administering Bureau programs; developing, amending, and revising land use plans; and approving uses on the public lands;

(b) Promote conservation by maintaining, protecting, and restoring ecosystem resilience and intact landscapes, including habitat connectivity and old-growth forests;

(c) Integrate the fundamentals of land health and related standards and guidelines into resource management for all uses and activities on BLM-managed lands;

(d) Incorporate inventory, assessment, and monitoring principles into decision-making and use this information to identify trends and implement adaptive management strategies;

(e) Accelerate restoration and improvement of degraded public lands, air, and waters to properly functioning and desired conditions;

(f) Manage for ecosystems and their components to adapt, absorb, or recover from the effects of disturbances or environmental change through conservation, protection, restoration, or improvement of essential structures, functions, and redundancy of ecological patterns across the landscape;

(g) Provide for healthy lands and waters that support sustainable outdoor recreation experiences for current and future generations;

(h) Prevent permanent impairment or unnecessary or undue degradation of public lands;

(i) Improve engagement and co-stewardship of public lands with Tribal entities and promote the use of Indigenous Knowledge in decision-making; and

(j) Advance environmental justice through restoration and mitigation actions.

§ 6101.3 Authority.

These regulations are issued under the authority of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1701 *et seq.*) as amended and section 2002 of the Omnibus Public Land Management Act of 2009 (16 U.S.C. 7202). Implementation of this part is subject to all applicable law.

§ 6101.4 Definitions.

As used in this part, the term:

(a) *Casual use* means any short-term, noncommercial activity that does not cause appreciable damage or disturbance to the public lands or their resources or improvements and that is not prohibited by closure of the lands to any such activity.

(b) *Conservation* means the management of natural resources to promote protection and restoration. Conservation actions are effective at building resilient lands and are designed to reach desired future conditions through protection, restoration, and other types of planning, permitting, and program decision-making.

(c) *Disturbance* means changes in environmental conditions, either discrete or chronic. Disturbances may be viewed as ''characteristic'' when ecosystems and/or species have evolved to survive, exploit, and even depend on a disturbance or ''uncharacteristic'' when attributes of the disturbance (*e.g.,* type, timing, frequency, magnitude, duration) are outside prevailing background conditions. Disturbances may be natural or human-caused.

(d) *Ecosystem resilience* means the capacity of ecosystems (*e.g.,* old-growth forests and woodlands, sagebrush core areas) to maintain or regain their fundamental composition, structure, and function (including maintaining habitat connectivity and providing ecosystem services) when affected by disturbances such as drought, wildfire, and nonnative invasive species.

(e) *Effects* means the direct, indirect, and cumulative impacts, as defined in 40 CFR 1508.1(g), from a public land use. Effects and impacts as used in these regulations are synonymous.

(f) *High-quality information* means information that promotes reasoned, evidence-based agency decisions. Information that meets the standards for objectivity, utility, and integrity as set forth in the Department's Information Quality Guidelines [17] qualifies as high-quality information. Indigenous Knowledge qualifies as high-quality information when it is gained by prior, informed consent free of coercion, and generally meets the standards for high-quality information.

(g) *Important, scarce, or sensitive resources:*

(1) ''Important resources'' means resources that the BLM has determined to warrant special consideration, consistent with applicable law.

(2) ''Scarce resources'' means resources that are not plentiful or abundant and may include resources that are experiencing a downward trend in condition.

[17] U.S. Department of the Interior, Information Quality Guidelines, *https://www.doi.gov/ocio/policy-mgmt-support/information-quality-guidelines.*

(3) ''Sensitive resources'' means resources that are delicate and vulnerable to adverse change, such as resources that lack resilience to changing circumstances.

(h) *Indigenous Knowledge* means a body of observations, oral and written knowledge, innovations, technologies, practices, and beliefs developed by Indigenous Peoples through interaction and experience with the environment. Indigenous Knowledge is applied to phenomena across biological, physical, social, cultural, and spiritual systems. Indigenous Knowledge can be developed over millennia, continue to develop, and include understanding based on evidence acquired through direct contact with the environment and long-term experiences, as well as extensive observations, lessons, and skills passed from generation to generation. Indigenous Knowledge is developed, held, and stewarded by Indigenous Peoples and is often intrinsic within Indigenous legal traditions, including customary law or traditional governance structures and decision-making processes. Other terms, such as Traditional Knowledge, Traditional Ecological Knowledge, Genetic Resources associated with Traditional Knowledge, Traditional Cultural Expression, Tribal Ecological Knowledge, Native Science, Indigenous Applied Science, Indigenous Science, and others, are sometimes used to describe this knowledge system.

(i) *In-lieu fee program* means a program involving the restoration, establishment, and/or enhancement and protection of resources at specific sites through funds paid to a local or State government agency, non-profit organization that qualifies for tax-exempt status in accordance with Internal Revenue Code (IRC) section 501(c)(3), or Tribal organization to satisfy compensatory mitigation requirements for adverse impacts resulting from BLM-authorized public land uses. Collected funds are pooled and expended on projects that provide compensatory mitigation for the same types of resource impacts. Similar to a mitigation bank, an in-lieu fee program sells mitigation credits to permittees whose obligation to provide compensatory mitigation is then transferred to the in-lieu program sponsor.

(j) *Intact landscape* means a relatively unfragmented landscape free of local conditions that could permanently or significantly disrupt, impair, or degrade the landscape's composition, structure, or function. Intact landscapes are large enough to maintain native biological diversity, including viable populations of wide-ranging species. Intact landscapes provide critical ecosystem services and are resilient to disturbance and environmental change and thus may be prioritized for conservation action. For example, an intact landscape would have minimal fragmentation from roads, fences, and dams; low densities of agricultural, urban, and industrial development; and minimal pollution levels.

(k) *Intactness* means a measure of the degree to which human influences, which can include invasive species and unnatural wildfire, alter or impair the structure, function, or composition of a landscape. Areas experiencing a natural fire regime can be intact.

(l) *Land health* means the degree to which the integrity of the soil, water, and ecological processes sustain habitat quality and ecosystem functions.

(m) *Landscape* means an area that is spatially heterogeneous in at least one factor of interest which may include common management concerns or conditions. The landscape is not defined by the size of the area, but rather by the interacting elements that are relevant and meaningful in a management context. Landscapes may be defined in terms of aquatic conditions, such as watersheds, or terrestrial conditions, such as ecoregions.

(n) *Mitigation* means:

(1) avoiding the impacts of a proposed action by not taking a certain action or parts of an action;

(2) minimizing impacts by limiting the degree or magnitude of the action and its implementation;

(3) rectifying the impact of the action by repairing, rehabilitating, or restoring the affected environment;

(4) reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action; and

(5) compensating for the impact of the action by replacing or providing substitute resources or environments. In practice, the mitigation sequence is often summarized as avoid, minimize, and compensate. The BLM generally applies mitigation hierarchically: first avoid, then minimize, and then compensate for any residual impacts from proposed actions.

(o) *Mitigation bank* means a site, or suite of sites, where resources are restored, established, enhanced, or protected for the purpose of providing compensatory mitigation for impacts to the same types of resources from BLM-authorized public land uses. In general, the sponsor of a mitigation bank sells mitigation credits to permittees whose obligation to provide compensatory mitigation is then transferred to the mitigation bank sponsor.

(p) *Mitigation fund* means an account established by a mitigation fund holder through a written agreement with the BLM. Permittees with compensatory mitigation requirements may deposit funds with the fund holder, when approved to do so by the BLM. Funds are then expended by the fund holder on projects that mitigate for the same types of resources that were impacted as a result of BLM-authorized land uses.

(q) *Mitigation strategies* means documents that identify, evaluate, and communicate potential mitigation needs and mitigation measures in a geographic area, at relevant scales, in advance of anticipated public land uses.

(r) ''Monitoring'' means the periodic observation and orderly collection of data to evaluate:

(1) existing conditions;

(2) the effects of management actions; or

(3) the effectiveness of actions taken to meet management objectives.

(s) *Permittee* means any person or other legal entity that has a valid permit, right-of-way grant, lease, or other BLM land use authorization.

(t) *Protection* means the act or process of conservation by maintaining the existence of resources while preventing degradation, damage, or destruction. Protection is not synonymous with preservation and allows for active management or other uses consistent with multiple use and sustained yield principles.

(u) *Public lands* means any surface estate or interests in the surface estate owned by the United States and administered by the Secretary of the Interior through the BLM without regard to how the United States acquired ownership.

(v) *Reclamation* means, when used in relation to individual project goals and objectives, practices intended to achieve an outcome that reflects the final goal to restore the character and productivity of the land and water. Components of reclamation include, as applicable:

(1) Isolating, controlling, or removing toxic or deleterious substances;

(2) Regrading and reshaping to conform with adjacent landforms, facilitate revegetation, control drainage, and minimize erosion;

(3) Rehabilitating fisheries or wildlife habitat;

(4) Placing growth medium and establishing self-sustaining revegetation;

(5) Removing or stabilizing buildings, structures, or other support facilities;

(6) Plugging drill holes and closing underground workings; and

(7) Providing for post-activity monitoring, maintenance, or treatment.

(w) *Restoration* means the process or act of conservation by passively or actively assisting the recovery of an ecosystem that has been degraded, damaged, or destroyed to a more natural, native ecological state.

(x) *Significant causal factor* means a use, activity, or disturbance that prevents an area from achieving or making significant progress toward achieving one or more land health standards. To be a significant factor, a use may be one of several causal factors in contributing to less-than-healthy conditions; it need not be the sole causal factor inhibiting progress toward the standards.

(y) *Significant progress* means measurable or observable changes in the indicators that demonstrate improved land health. Acceptable levels of change must be realistic in terms of the capability of the resource but must also be as expeditious and effective as practical.

(z) *Sustained yield* means the achievement and maintenance in perpetuity of a high-level annual or regular periodic output of the various renewable resources of BLM-managed lands consistent with multiple use and without permanent impairment of the productivity of the land. Preventing permanent impairment means that renewable resources are not permanently depleted and that desired future conditions are met for future generations. Ecosystem resilience is essential to the BLM's ability to manage for sustained yield.

(aa) *Unnecessary or undue degradation* means harm to resources or values that is not necessary to accomplish a use's stated goals or is excessive or disproportionate to the proposed action or an existing disturbance. Unnecessary or undue degradation includes two distinct elements: ''Unnecessary degradation'' means harm to land resources or values that is not needed to accomplish a use's stated goals. For example, approving a proposed access road causing damage to critical habitat for a plant listed as endangered under the Endangered Species Act that could be located without any such impacts and still provide the needed access may result in unnecessary degradation. ''Undue degradation'' means harm to land resources or values that is excessive or disproportionate to the proposed action or an existing disturbance. For example, approving a proposed access road causing damage to the only remaining critical habitat for a plant listed as endangered under the Endangered Species Act, even if there is not another location for the road, may result in undue degradation. The statutory obligation to prevent ''unnecessary or undue degradation'' applies when either unnecessary degradation or undue degradation, and not necessarily both, is implicated.

(bb) *Watershed condition assessment* means a process for assessing and synthesizing information on the condition of soil, water, habitats, and ecological processes within watersheds relative to the BLM's land health fundamentals. A watershed condition assessment may include assessment of one or more of watershed physical and biological characteristics, landscape intactness, and disturbances.

§ 6101.5 Principles for Ecosystem Resilience.

(a) Except where otherwise provided by law, public lands must be managed under the principles of multiple use and sustained yield.

(b) To ensure multiple use and sustained yield, the BLM's management must conserve the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archeological values; preserve and protect certain public lands in their natural condition (including ecological and environmental values); maintain the productivity of renewable natural resources in perpetuity; and consider the long-term needs of future generations, without permanent impairment of the productivity of the land.

(c) The BLM must conserve renewable natural resources at a level that maintains or improves future resource availability and ecosystem resilience, in a manner consistent with multiple use and sustained yield.

(d) Authorized officers must implement the foregoing principles through:

(1) Conservation as a land use within the multiple use framework, including in decision-making, authorization, and planning processes;

(2) Protection and maintenance of the fundamentals of land health and ecosystem resilience;

(3) Restoration and protection of public lands to support ecosystem resilience, including habitat connectivity and old-growth forests;

(4) Use of the full mitigation hierarchy to address impacts to species, habitats, and ecosystems from land use authorizations; and

(5) Prevention of unnecessary or undue degradation.

Subpart 6102—Conservation Use To Achieve Ecosystem Resilience

§ 6102.1 Protection of Landscape Intactness.

(a) The BLM must manage certain landscapes to protect their intactness, including habitat connectivity and old-growth forests. This requires:

(1) Maintaining ecosystem resilience and habitat connectivity through conservation actions;

(2) Conserving landscape intactness when managing compatible uses, especially where development or fragmentation that could permanently impair ecosystem resilience has the potential to occur on public lands;

(3) Maintaining or restoring resilient ecosystems through habitat and ecosystem restoration projects that are implemented over broader spatial and longer temporal scales;

(4) Coordinating and implementing actions across BLM programs, offices, and partners to protect intact landscapes; and

(5) Pursuing management actions that maintain or mimic characteristic disturbance, or mimic natural disturbance, when maintaining it is not possible.

(b) Authorized officers will seek to prioritize actions that conserve and protect landscape intactness in accordance with § 6101.2.

§ 6102.2 Management to Protect Intact Landscapes.

(a) The BLM will maintain an inventory of landscape intactness as a resource value using watershed condition assessments (*see* § 6103.2(a)) to establish a consistent baseline condition.

(b) When updating a resource management plan under part 1600 of this chapter, the BLM will use a baseline condition of intactness and available high-quality information about landscape intactness, such as watershed condition assessments, environmental disturbances, and monitoring (*see* § 6103.2), to:

(1) Identify and delineate boundaries for intact landscapes within the planning area, taking into consideration habitat connectivity and migration corridor data;

(2) Evaluate alternatives to protect intact landscapes or portions of the intact landscapes from activities that would permanently or significantly disrupt, impair, or degrade the ecosystem's structure or functionality of the intact landscapes; and

(3) Identify which intact landscapes or portions of intact landscapes will be managed for protection consistent with

the principles enumerated in § 6102.1(a).

(c) The BLM will identify desired conditions and landscape objectives to guide implementation of decisions regarding management of intact landscapes, habitat connectivity, and old-growth forests. As part of carrying out paragraph (b) of this section, the BLM will seek to:

(1) Establish partnerships to work across Federal and non-Federal lands to promote and protect intact landscapes;

(2) Work with communities to identify geographic areas important for their strategic growth and development in order to allow for better identification of the most suitable areas to protect intact landscapes and habitat connectivity;

(3) Consult with Tribes to identify opportunities for co-stewardship to protect intact landscapes (*see* § 6102.5(b)(4) through (6)); and

(4) Use high-quality information including standardized quantitative monitoring to evaluate the effectiveness of management actions for ecosystem resilience (*see* § 6103.2).

(d) When determining whether to acquire lands or interests in lands through purchase, donation, or exchange, authorized officers must prioritize the acquisition of lands or interests in lands that would further protect and connect intact landscapes and functioning ecosystems.

(e) Authorized officers must collect and track landscape intactness data to support minimizing surface disturbance and inform conservation actions. This information must be included in a publicly available national tracking system.

§ 6102.3 Restoration.

(a) The BLM must emphasize restoration on the public lands to achieve its multiple use and sustained yield mandate.

(b) In determining the restoration actions required to achieve recovery of ecosystems and promote resilience, the BLM must consider the causes of degradation, the recovery potential of the ecosystem, and the allowable uses in the governing land use plan, such as whether an area is managed for recreation or is degraded land prioritized for development. The BLM must then develop commensurate restoration goals and objectives (*see* § 6103.1.1).

(c) The BLM should employ management actions to promote restoration. Over the long-term, restoration actions must be durable, self-sustaining, and expected to persist in a manner that supports land health and ecosystem resilience.

(d) When designing and implementing restoration actions on public lands, including authorizing restoration leases, authorized officers must adhere to the following principles:

(1) Ensure that restoration actions address causes of degradation, focus on process-based solutions, and where possible maintain attributes and resource values associated with the potential or capability of the ecosystem;

(2) Ensure that actions are designed, implemented, and monitored at appropriate spatial and temporal scales using suitable treatments and tools to achieve desired outcomes;

(3) Coordinate and implement actions across BLM programs, with partners, and in consideration of existing uses to develop holistic restoration actions;

(4) Ensure incorporation of locally appropriate best management practices, high-quality information, and adaptive management that supports restoration;

(5) Identify opportunities to implement nature-based or low-tech restoration activities and use seed from native plants; and

(6) Consult with Tribes to identify opportunities for co-stewardship or collaboration (*see* § 6102.5(b)(4) through (6)).

§ 6102.3.1 Restoration Prioritization and Planning.

(a) Authorized officers must identify measurable and quantifiable restoration outcomes consistent with the restoration principles enumerated in § 6102.3 in all resource management plans.

(b) Authorized officers will, at least every 5 years, identify priority landscapes for restoration consistent with resource management plan objectives and the restoration principles enumerated in § 6102.3. In doing so, authorized officers must consider:

(1) Current conditions and causes of degradation as indicated by watershed condition assessments, existing land health assessments, evaluations, and determinations, and other high-quality information (*see* § 6103.2);

(2) The likelihood of success of restoration activities to achieve resource or conservation objectives including ecosystem resilience;

(3) Where restoration actions may have the most social and economic benefits or work to address environmental justice, including impacts on communities with environmental justice concerns; and

(4) Where restoration or mitigation can minimize or offset unnecessary or undue degradation, such as ecosystem conversion, fragmentation, habitat loss, or other negative outcomes that permanently impair ecosystem resilience.

(c) For priority landscapes identified in accordance with this subpart, authorized officers must periodically, and at least every 5 years, develop or amend restoration plans consistent with resource management plan objectives in accordance with part 1600 of this chapter. Each restoration plan must include goals, objectives, and management actions that are:

(1) Consistent with the restoration principles enumerated in § 6102.3;

(2) Commensurate with recovery potential;

(3) Evaluated against measurable objectives, including to facilitate adaptive management to achieve outcomes supporting ecosystem resilience (*see* subpart 6103);

(4) Developed consistent with scientifically accepted standards and principles for restoration; and

(5) Consistent with statewide and regional needs as identified in the assessment of priority landscapes for restoration as identified in this subpart.

(d) Authorized officers must track restoration implementation and progress toward achieving goals at appropriate temporal scales. If restoration goals are not met, authorized officers must assess why restoration outcomes are not being achieved and what, if any, additional resources or changes to management are needed to achieve restoration goals.

§ 6102.4 Restoration and Mitigation Leasing.

(a) The BLM may authorize restoration leases or mitigation leases under such terms and conditions as the authorized officer determines are appropriate for the purpose of restoring degraded landscapes or mitigating impacts of other uses.

(1) Restoration or mitigation leases on the public lands may be authorized for the following purposes:

(i) Restoration of land and resources by passively or actively assisting the recovery of an ecosystem that has been degraded, damaged, or destroyed to a more natural, resilient ecological state; and

(ii) Mitigation to offset impacts to resources resulting from other land use authorizations.

(2) Authorized officers may issue restoration or mitigation leases to any qualified entity that can demonstrate capacity for implementing restoration or mitigation projects (as appropriate) and meets the lease requirements. Consistent with the lease adjudication practices established in 43 CFR 2920, qualified entities for restoration or mitigation

leases may be individuals, businesses, non-governmental organizations, Tribal governments, conservation districts, or State fish and wildlife agencies. Qualified entities for a mitigation lease to establish an in-lieu fee program are limited to non-governmental organizations, State fish and wildlife agencies, and Tribal government organizations. Restoration and mitigation leases may not be held by a foreign person as that term is defined in 31 CFR 802.221.

(3) Restoration or mitigation leases shall be issued for a term consistent with the time required to achieve their objective.

(i) A lease issued for purposes of restoration may be issued for a maximum term of 10 years, and all activities taken under the lease shall be reviewed mid-term for consistency with the lease provisions.

(ii) A lease issued for purposes of mitigation shall be issued for a term commensurate with the impact it is mitigating, and all activities taken under the lease reviewed every 5 years for consistency with the lease provisions.

(iii) Authorized officers may renew a restoration or mitigation lease if necessary to serve the purpose for which the lease was first issued, provided that the lease holder is in compliance with the terms and conditions of the lease and renewal is consistent with applicable law. Such renewal can be for a period no longer than the original term of the lease.

(4) Subject to valid existing rights and applicable law, once the BLM has issued a lease, the BLM shall not issue new authorizations to use the leased lands if the use would be incompatible with the authorized restoration or mitigation use.

(5) No land use authorization is required under the regulations in this part for casual use of the public lands covered by a restoration or mitigation lease.

(b) The application process for a restoration or mitigation lease and for renewal of such a lease is as follows:

(1) An application for a restoration or mitigation lease must be filed using an approved application form with the Bureau of Land Management office having jurisdiction over the public lands covered by the application.

(2) The filing of an application gives the applicant no right to use the public lands.

(3) Acceptance of an application or approval of a lease is not guaranteed and is at the discretion of the authorized officer.

(4) Actions that pertain to or address geographic areas or resource conditions previously identified as needing restoration by the BLM through watershed condition assessments and existing land health assessments, land health evaluations, an existing restoration plan, a mitigation strategy, or high-quality inventory, assessment, and monitoring information shall be given priority for consideration (*see* subpart 6103).

(c) An application for a restoration or mitigation lease must comply with the following requirements:

(1) An application must include a restoration or mitigation development plan that describes the proposed restoration or mitigation use in sufficient detail to enable authorized officers to evaluate the feasibility, impacts, benefits, costs, threats to public health and safety, collaborative efforts, and conformance with BLM plans, programs, and policies, including compatibility with other uses.

(2) The development plan shall include, but not be limited to:

(i) Results from available assessments, inventory and monitoring efforts, or other high-quality information (*see* subpart 6103) that identify the current conditions of the site(s) of the proposed restoration or mitigation action;

(ii) The desired future condition of the proposed lease area including clear goals, objectives, and measurable performance criteria needed to determine progress toward achieving the objectives;

(iii) Justification for passive restoration or mitigation if proposed;

(iv) A description of all facilities for which authorization is sought, including access needs and any other special types of authorizations that may be needed;

(v) A map of sufficient scale to allow the required information to be legible as well as a legal description of primary and alternative project locations;

(vi) Justification of the total acres proposed for the restoration or mitigation lease;

(vii) A schedule for restoration activities if applicable; and

(viii) Information on outreach already conducted or to be conducted with existing permittees, lease holders, adjacent land managers or owners, and other interested parties.

(3) Restoration lease development plans must be consistent with § 6102.3 and mitigation lease development plans must be consistent with § 6102.5.1.

(4) Applicants must submit the following additional information, upon request of the authorized officer:

(i) Additional high-quality information, if such information is necessary for the BLM to decide whether to issue, issue with modification, or deny the proposed lease;

(ii) Documentation of or proof of application for any required private, State, local, or other Federal agency licenses, permits, easements, certificates, or other approvals; and

(iii) Evidence that the applicant has, or will have prior to commencement of lease activities, the technical and financial capability to operate, maintain, and terminate the authorized lease activities.

(d) When reviewing restoration and mitigation lease applications, authorized officers will consider the following factors, along with other applicable legal requirements, which will make lease issuance more likely:

(1) Lease outcomes that are consistent with the restoration principles in § 6102.3(d);

(2) Desired future conditions that are consistent with the management objectives and allowable uses in the governing land use plan, such as an area managed for recreation or prioritized for development;

(3) Collaboration with existing permittees, leaseholders, and adjacent land managers or owners;

(4) Outreach to or support from local communities; or

(5) Consideration of environmental justice objectives.

(e) If approved, the leaseholder shall provide a monitoring plan that describes how the terms and conditions of the lease will be applied, the monitoring methodology and frequency, measurable criteria, and adaptive management triggers.

(1) The lease holder shall provide a lease activity report annually and at the end of the lease period. At a minimum, the report shall specify:

(i) The restoration or mitigation activities taken as of the time of the report;

(ii) Any barriers to meeting the stated purpose of the lease;

(iii) Proposed steps to resolve any identified barriers; and

(iv) Monitoring information and data that meet BLM methodology requirements and data standards (*see* § 6103.2(d)).

(2) Additional requirements for development plans and monitoring plans for mitigation leases are provided in § 6102.5.1.

(f) An approved lease does not convey exclusive rights to use the public lands to the lease holder The authorized officer retains the discretion to determine compatibility of the renewal of existing authorizations and future land use proposals on lands subject to restoration or mitigation leases.

(g) A restoration or mitigation lease will not preclude access to or across leased areas for casual use, recreation use, research use, or other use taken pursuant to a land use authorization that is compatible with the approved restoration or mitigation use.

(h) Existing access that accommodates accessibility under section 504 of the Rehabilitation Act shall remain after a lease has been issued.

(i) A restoration or mitigation lease may only be amended, assigned, or transferred with the written approval of the authorized officer, and no amendment, assignment, or transfer shall be effective until the BLM has approved it in writing. Authorized officers may authorize assignment or transfer of a restoration or mitigation lease in their discretion if no additional rights will be conveyed beyond those granted by the original authorization, the proposed assignee or transferee is qualified to hold the lease, and the assignment or transfer is in the public interest.

(j) Administrative cost recovery, rents, and fees for restoration and mitigation leases will be governed by the provisions of 43 CFR 2920.6 and 2920.8, provided that the BLM may waive or reduce administrative cost recovery, fees, and rent of a restoration lease if the restoration lease is not used to generate revenue or satisfy the requirements of a mitigation program (*e.g.,* selling credits in an established market), and the restoration lease will enhance ecological or cultural resources or provide a benefit to the general public.

§ 6102.4.1 Termination and Suspension of Restoration and Mitigation Leases.

(a) If a restoration or mitigation lease provides by its terms that it shall terminate on the occurrence of a fixed or agreed-upon event, the restoration or mitigation lease shall automatically terminate by operation of law upon the occurrence of such event.

(b) A restoration or mitigation lease may be terminated by mutual written agreement between the authorized officer and the lease holder.

(c) Authorized officers have discretion to suspend or terminate restoration or mitigation leases under the following circumstances:

(1) Improper issuance of the lease;

(2) Noncompliance by the holder with applicable law, regulations, or terms and conditions of the lease;

(3) Failure of the holder to use the lease for the purpose for which it was authorized; or

(4) Impossibility of fulfilling the purposes of the lease.

(d) Upon determination that the holder has failed to comply with any terms or conditions of a lease and that such noncompliance adversely affects or poses a threat to land or public health or safety, or impacts ecosystem resilience, the authorized officer shall issue an immediate temporary suspension.

(1) The authorized officer may issue an immediate temporary suspension order orally or in writing at the site of the activity to the holder or a contractor or subcontractor of the holder, or to any representative, agent, employee, or contractor of any such holder, contractor, or subcontractor, and the suspended activity shall cease at that time. As soon as practicable, the authorized officer shall confirm the order by a written notice to the holder addressed to the holder or the holder's designated agent. The authorized officer may also take such action that the authorized officer considers necessary to address the adverse effects or threat to land or public health or safety or impacts to ecosystem resilience.

(2) The authorized officer may order immediate temporary suspension of an activity independent of any action that has been or is being taken by another Federal or State agency.

(3) Any time after an order of temporary suspension has been issued, the holder may file with the authorized officer a request for permission to resume activities authorized by the lease. The request shall be in writing and shall contain a statement of the facts supporting the request. The authorized officer may grant the request upon determination that the adverse effects or threat to land or public health or safety or impacts to ecosystem resilience are resolved.

(4) The authorized officer may render an order to either grant or deny the request to resume within 30 working days of the date the request is filed. If the authorized officer does not render an order on the request within 30 working days, the request shall be considered denied, and the holder shall have the same right to appeal as if an order denying the request had been issued.

(e) Process for termination or suspension other than temporary immediate suspension.

(1) Prior to commencing any proceeding to suspend or terminate a lease, the authorized officer shall give written notice to the holder of the legal grounds for such action and shall give the holder a reasonable time to address the legal basis the authorized officer identifies for suspension or termination.

(2) After due notice of termination or suspension to the holder of a restoration or mitigation lease, if grounds for suspension or termination still exist after a reasonable time, the authorized officer shall give written notice to the holder and refer the matter to the Office of Hearings and Appeals for a hearing before an administrative law judge pursuant to 43 CFR part 4. The authorized officer shall suspend or revoke the restoration or mitigation lease if the administrative law judge determines that grounds for suspension or revocation exist and that such action is justified.

(3) Authorized officers shall terminate a suspension order when they determine that the grounds for such suspension no longer exist.

(4) Upon termination of a restoration or mitigation lease, the holder shall, for 60 days after the notice of termination, retain authorization to use the associated public lands solely for the purposes of reclaiming the site to its pre-use conditions consistent with achieving land health fundamentals, unless otherwise agreed upon in writing or in the lease terms. If the holder fails to reclaim the site consistent with the requirements of the lease terms within a reasonable period, all authorization to use the associated public lands will terminate, but that shall not relieve the holder of liability for the cost of reclaiming the site.

§ 6102.4.2 Bonding for Restoration and Mitigation Leases.

(a) *Bonding obligations.* (1) Prior to the commencement of surface-disturbing or active management activities, the authorized officer may require the restoration or mitigation lease holder to submit a reclamation, decommission, or performance bond conditioned upon compliance with all the terms and conditions of the lease covered by the bond, as described in this subpart. For mitigation leases, the lease holder will usually be required to provide letters of credit or establish an escrow account for the full amount needed to ensure the development plan meets all performance criteria. The bond amounts shall be sufficient to ensure reclamation of the restoration and mitigation lease area(s) and the restoration of any lands or surface waters adversely affected by restoration or mitigation lease operations. Such restoration may be required after the abandonment or cessation of operations by the restoration or mitigation lease holder in accordance with, but not limited to, the standards and requirements set forth by authorized officers.

(2) Considerations for requiring a bond include, but are not limited to:

(i) The type and level of active restoration;

(ii) Amount and type of surface disturbing activity;

(iii) Proposed use of non-natural restoration methods, such as the use of pesticides;

(iv) Proposed use of experimental methods of restoration;

(v) Risk of compounding effects resulting from restoration activities, such as a proliferation of invasive species; and

(vi) Fire risk.

(3) Surety bonds shall be issued by qualified surety companies certified by the Department of the Treasury.

(4) Personal bonds shall be accompanied by:

(i) Cashier's check;

(ii) Certified check; or

(iii) Negotiable Treasury securities of the United States of a value equal to the amount specified in the bond. Negotiable Treasury securities shall be accompanied by a proper conveyance to the Secretary of full authority to sell such securities in case of default in the performance of the terms and conditions of a conservation use authorization.

(b) In lieu of bonds for each individual restoration or mitigation lease, holders may furnish a bond covering all restoration or mitigation leases and operations in any one State. Such a bond must be at least $25,000 and must be sufficient to ensure reclamation of all of the holder's restoration or mitigation lease area(s) and the restoration of any lands or surface waters adversely affected by restoration or mitigation lease operations in the State.

(c) All bonds shall be filed in the proper BLM office on a current form approved by the Office of the Director. A single copy executed by the principal or, in the case of surety bonds, by both the principal and an acceptable surety is sufficient. Bonds shall be filed in the Bureau State Office having jurisdiction of the restoration or mitigation lease covered by the bond.

(d) Default.

(1) Where, upon a default, the surety makes a payment to the United States of an obligation incurred under a restoration or mitigation lease, the face amount of the surety bond or personal bonds and the surety's liability thereunder shall be reduced by the amount of such payment.

(2) After default, where the obligation in default equals or is less than the face amount of the bond(s), the principal shall either post a new bond or restore the existing bond(s) to the amount previously held or a larger amount as determined by authorized officers. In lieu thereof, the principal may file separate or substitute bonds for each conservation use covered by the deficient bond(s). Where the obligation incurred exceeds the face amount of the bond(s), the principal shall make full payment to the United States for all obligations incurred that are in excess of the face amount of the bond(s) and shall post a new bond in the amount previously held or such larger amount as determined by authorized officers. The restoration of a bond or posting of a new bond shall be made within 6 months or less after receipt of notice from authorized officers.

(3) Failure to comply with these requirements may:

(i) Subject all leases covered by such bond(s) to termination under the provisions of this title;

(ii) Prevent the bond obligor or principal from acquiring any additional restoration or mitigation leases or interest therein under this subpart; and

(iii) Result in the bond obligor or principal being referred to the suspension and debarment program under 2 CFR part 1400 to determine if the entity will be suspended or debarred from doing business with the Federal Government.

§ 6102.5 Management Actions for Ecosystem Resilience.

(a) Authorized officers must:

(1) Identify priority watersheds, landscapes, and ecosystems that require protection and restoration efforts (*see* §§ 6102.2 and 6102.3.1);

(2) Develop and implement plans and strategies, including protection, restoration, and mitigation strategies that effectively manage public lands to protect and promote resilient ecosystems (*see* §§ 6102.1, 6102.3.1, 6102.5.1, 6103.1.2);

(3) Develop and implement monitoring and adaptive management strategies for maintaining sustained yield of renewable resources, accounting for changing landscapes, fragmentation, invasive species, and other disturbances (*see* § 6103.2);

(4) Report annually on the results of land health evaluations, and determinations (*see* § 6103.1.2);

(5) Ensure that watershed condition assessments incorporate consistent analytical approaches (*see* § 6103.2) both among neighboring BLM State Offices and with the fundamentals of land health; and

(6) Share watershed condition assessments in a publicly available national database to determine changes in watershed condition and record measures of success based on conservation and restoration goals.

(b) In taking management actions, and as consistent with applicable law and resource management plans, such as where an area is managed for recreation or is degraded land prioritized for development, authorized officers must:

(1) Make every effort to avoid authorizing uses of the public lands that permanently impair ecosystem resilience;

(2) Promote opportunities to support conservation and other actions that work toward achieving land health standards and ecosystem resilience;

(3) Issue decisions that promote the ability of ecosystems to passively recover or the BLM's ability to actively restore ecosystem composition, structure, and function;

(4) Meaningfully consult with Indian Tribes and Alaska Native Corporations during the decision-making process on actions that are determined, after allowing for Tribal input, to potentially have a substantial effect on the Tribe or Corporation;

(5) Allow State, Tribal, and local agencies to serve as joint lead agencies consistent with 40 CFR 1501.7(b) or as cooperating agencies consistent with 40 CFR 1501.8(a) in the development of environmental impact statements or environmental assessments;

(6) Respect Indigenous Knowledge, by:

(i) Improving engagement and expanding co-stewardship of public lands with Tribal entities;

(ii) Encouraging Tribes to suggest ways in which Indigenous Knowledge can be used to inform the development of alternatives, analysis of effects, and when necessary, identification of mitigation measures; and

(iii) Communicating to Tribes in a timely manner and in an appropriate format how their Indigenous Knowledge was included in decision-making, including addressing management of sensitive information;

(7) Seek opportunities to restore or protect ecosystem resilience when the effects of potential uses are unknown; and

(8) Provide justification for decisions that may impair ecosystem resilience.

(c) Authorized officers must use high-quality inventory, assessment, and monitoring data, as available and appropriate, to evaluate resource conditions and inform decision-making across program areas (*see* § 6103.2(c)), specifically by:

(1) Identifying clear goals or desired outcomes relevant to the management decision;

(2) Gathering high-quality information relevant to the management decision, including standardized quantitative monitoring data and data about land health;

(3) Selecting relevant indicators for each applicable management question (*e.g.,* land health standards, restoration effectiveness, assessments of intactness);

(4) Establishing a framework for translating indicator values to condition categories (such as quantitative monitoring objectives or science-based conceptual models); and

(5) Summarizing results and ensuring that a clear and understandable rationale is documented, explaining how the data were used to make the decision.

§ 6102.5.1 Mitigation.

(a) The BLM will apply the mitigation hierarchy to avoid, minimize, and compensate, as appropriate, for adverse impacts to resources when authorizing uses of public lands. As appropriate, the authorized officer may identify specific mitigation approaches or requirements to address resource impacts through land use plans or in other decision documents.

(b) For important, scarce, or sensitive resources, authorized officers shall apply the mitigation hierarchy with particular care, with the goal of eliminating, reducing, and/or offsetting impact on the resource, consistent with applicable law.

(c) When implementing the mitigation hierarchy, including authorizing mitigation leases, the BLM will:

(1) Use a landscape-scale approach to develop and implement mitigation strategies that identify mitigation needs and opportunities in a geographic area, including opportunities for the siting of large, market-based mitigation programs or projects (*e.g.,* mitigation banks) on public lands;

(2) Use high-quality information to inform the identification and analysis of adverse impacts, to determine appropriate mitigation programs or projects for those impacts, and to achieve appropriate and effective mitigation outcomes;

(3) Require identification of performance criteria for mitigation programs or projects, effectiveness monitoring of those performance criteria, and reports that assess the achievement of those performance criteria;

(4) Use adaptive management principles to guide and improve mitigation outcomes; and

(5) Ensure that any compensatory mitigation programs or projects are commensurate with the applicable adverse impacts and that the required compensatory mitigation programs and projects are durable, additional, and timely.

(6) As used in this section, the terms *additional, commensurate, durable,* and *timely* have the following definitions:

(i) *Additional* means the compensatory mitigation program or project's benefit is demonstrably new and would not have occurred without the compensatory mitigation measure.

(ii) *Commensurate* means the compensatory mitigation program or project is reasonably related and proportional to the adverse impact from authorizing uses of public lands.

(iii) *Durable* means the maintenance of the effectiveness of a mitigation program or project, including resource, administrative, and financial considerations.

(iv) *Timely* means the lack of a time lag between the impact to the resources and the achievement of the outcomes of the associated compensatory mitigation.

(d) The BLM may approve, through a formal agreement, a third-party mitigation fund holder to administer funds for the implementation of compensatory mitigation programs or projects. A BLM-approved third-party mitigation fund holder may:

(1) Collect mitigation funds from permittees;

(2) Manage funds in accordance with agency decision documents, use authorizations and applicable law; and

(3) Disperse those funds in accordance with agency decision documents, use authorizations, and applicable law.

(e) Approved third-party mitigation fund holders must file with the BLM annual fiscal reports. To qualify as a third-party mitigation fund holder, the entity must either:

(1) Qualify for tax-exempt status in accordance with Internal Revenue Code section 501(c)(3); provide evidence that they can successfully hold and manage mitigation accounts; be a public charity bureau for the State in which the mitigation area is located, or otherwise comply with applicable State laws; be a third party organizationally separate from and having no corporate or family connection to the entity accomplishing the mitigation program or project, BLM employees, or the permittee; adhere to generally accepted accounting practices that are promulgated by the Financial Accounting Standards Board, or any successor entity; and have the capability to hold, invest, and manage the mitigation funds to the extent allowed by law; or

(2) Be a State or local government agency, if the government agency is able to demonstrate, to the satisfaction of the BLM, that:

(i) it is acting as a fiduciary for the benefit of the mitigation project or site and can show that it has the authority and ability to collect the funds, protect the account from being used for purposes other than the management of the mitigation project or site, and disburse the funds to the entities conducting the mitigation project or management of the mitigation site;

(ii) it is organizationally separate from and has no corporate or family connection to the entity accomplishing the mitigation program or project, BLM employees, or the permittee; and

(iii) it adheres to generally accepted accounting practices that are promulgated by the Governmental Accounting Standards Board or any successor entity.

(f) Authorized officers will require mitigation leases and collect annual rent at fair market value for large or otherwise substantial compensatory mitigation programs or projects on public lands, including mitigation banks and in-lieu fee programs. Mitigation leases may be required for other compensatory mitigation projects on public lands at the discretion of the authorized officer.

(g) In addition to the general requirements for mitigation leases (§ 6102.4), in some circumstances, authorized officers may require that mitigation lease holders submit to the agency a formal agreement with a qualified mitigation fund holder as defined in paragraph (d) of this section.

(h) An application for a mitigation lease for a mitigation bank or an in-lieu fee program, in addition to the requirements in (§ 6102.4(c)), must also include sufficient information about the anticipated demand for and duration of the mitigation bank or in-lieu fee program, the anticipated types of mitigation projects that will be conducted, and the methods that will be used to generate, evaluate, assess, and maintain the mitigation projects.

(i) Authorized officers will ensure that compensatory mitigation programs and projects, including those with mitigation leases, are tracked in the appropriate BLM data systems.

Subpart 6103—Managing Land Health To Achieve Ecosystem Resilience

§ 6103.1 Land Health Standards.

(a) The BLM shall develop national land health standards that facilitate progress toward achieving the following fundamentals of land health across all ecosystems on lands managed by the BLM:

(1) Watersheds are in, or are making significant progress toward, properly functioning physical condition, including their upland, riparian-wetland, and aquatic components; soil and plant conditions support infiltration, soil moisture storage, and the release of water that are in balance with climate and landform and maintain or improve water quality, water quantity, and timing and duration of flow.

(2) Ecological processes, including the hydrologic cycle, nutrient cycle, and energy flow, are maintained, or there is significant progress toward their attainment, in order to support healthy biotic populations and communities.

(3) Water quality complies with State water quality standards and achieves, or is making significant progress toward achieving, BLM management objectives established in the land use plan, such as meeting wildlife needs.

(4) Habitats are, or are making significant progress toward being, restored or maintained for Federal threatened and endangered species, Federal proposed or candidate threatened and endangered species, and other special status species.

(b) Land health fundamentals will be advanced through national land health standards that, at a minimum, address the following resources, processes, and values:

(1) Upland hydrologic function;

(2) Riparian, wetland, and aquatic hydrologic function;

(3) Upland ecological processes and biotic communities, including connectivity, and intactness of native plant and animal habitats;

(4) Riparian, wetland, and aquatic ecological processes and biotic communities including condition, connectivity, and intactness of native plant and animal habitats;

(5) Water quality; and

(6) Habitat condition connectivity and intactness for Federal threatened and endangered species, Federal proposed or candidate threatened and endangered species, and other special status species.

(c) To facilitate land health evaluations, the national land health standards will include indicators that are broadly applicable across the major ecosystem or habitat types (*e.g.,* forest, rangeland, cold water fisheries) the BLM manages, and will include indicators derived from standardized datasets.

(d) Authorized officers must manage all program areas in accordance with the fundamentals of land health and standards, as provided in this subpart. Authorized officers must adopt the national standards and indicators, and may, when necessary, incorporate geographically distinct land health standards and indicators to evaluate rare or unique habitat or ecosystem types (*e.g.,* permafrost) if such habitats or ecosystems cannot be evaluated using the national land health standards and indicators.

(e) Rangeland health standards developed under 43 CFR subpart 4180 will be reviewed and amended or supplemented as necessary to incorporate the national standards and indicators within 3 years of the effective date of these regulations. Subsequently, authorized officers shall review all land health standards for sufficiency at least every 10 years.

(f) Amended land health standards must be approved by the appropriate BLM State Director prior to implementation.

§ 6103.1.1 Management for Land Health.

(a) To facilitate ecosystem resilience, authorized officers should use watershed condition assessments (*see* § 6103.2), and land health evaluations and causal factor determinations to support decision-making. Such action promotes efficiency, supports environmental analysis, and streamlines decision-making.

(b) To facilitate ecosystem resilience, authorized officers must manage all program areas to progress toward achieving land health standards.

(1) Authorized officers must apply approved land health standards, as revised from rangeland health standards previously established under subpart 4180 of this chapter (fundamentals of rangeland health), across all ecosystems managed by the BLM.

(2) Programs that authorize and manage uses or implement management actions on public land will develop management guidelines, which are best management practices designed to facilitate progress toward achievement and maintenance of land health standards.

(i) Authorized officers may develop or adopt additional management guidelines to address local ecosystems and management practices.

(ii) Programs and authorized officers will review management guidelines for sufficiency and make necessary revisions at least every 10 years in conjunction with the review of land health standards described in this subpart.

(c) Land use plans must identify the allocations and actions anticipated to achieve desired land health outcomes, including actions to maintain or restore land health in accordance with the land health standards. These actions include, but are not limited to, prioritizing development in degraded areas as well as prioritizing and implementing restoration actions (*see* § 6102.3).

(d) Land use plans shall identify statutory, regulatory, and other requirements that may prevent achievement of land health standards.

(1) Best management practices and mitigation measures to minimize effects to land health resulting from these requirements should be identified and required where practicable.

(2) Environmental effects analysis, consistent with NEPA requirements, for proposed management actions must consider effects to relevant land health standards.

§ 6103.1.2 Land Health Evaluations and Determinations.

(a) Authorized officers shall rely on watershed condition assessments when possible to complete land health evaluations for BLM-managed lands on a periodic basis, at least every 10 years (§ 6103.2).

(b) Authorized officers must determine the priority landscape and appropriate scale for completing land health evaluations based on resource concerns and, as necessary, to support decision-making processes.

(c) Authorized officers must consider available watershed condition assessments and existing land health assessments, evaluations, and determinations in the course of decision-making processes for all program areas.

(d) Land health evaluations interpret watershed condition assessments, including locally relevant high-quality information to draw conclusions about whether land health standards are achieved on public lands. In the course of conducting land health evaluations, authorized officers should:

(1) Consider multiple lines of evidence to evaluate achievement of each standard;

(2) Identify trends toward or away from desired conditions through analysis of high-quality information available over relevant time periods and spatial scales;

(3) Document the rationale and findings as to whether each land health standard is achieved or significant progress is being made towards its achievement; and

(4) Develop an interdisciplinary monitoring plan with quantitative objectives that can be measured to demonstrate significant progress when a land health evaluation report identifies that any standard is not achieved but significant progress is being made towards achievement.

(e) When conducting a land health evaluation, if the authorized officer

finds that resource conditions are achieving or making significant progress toward achieving land health standards, no additional land health analysis is needed to authorize a use or permit activities.

(f) When conducting a land health evaluation, if the authorized officer finds that resource conditions are not achieving or making significant progress toward achieving land health standards, a documented causal factor determination must be prepared as soon as practicable but no later than 1 year after completion of the land health evaluation identifying the nonachievement. Causal factor determinations use available data to identify significant causal factors and describe contributing causal factors or conditions leading to non-achievement of standards.

(1) If the authorized officer determines sufficient information exists to identify and address the significant causal factors preventing resources from achieving or making significant progress towards achieving land health standards, no further land health analysis is required to address such factors.

(2) If the authorized officer determines insufficient information exists to identify and address the significant causal factors preventing resources from achieving or making significant progress to achieving land health standards, additional information, assessment and evaluation may be needed at finer scale.

(3) The authorized officer must take appropriate actions to facilitate achievement or significant progress toward achievement of land health standards as soon as practicable, unless otherwise specified in the land use plan, or when significant causal factors are outside of BLM control (*e.g.,* lack of streamflow due to dewatering on connected lands not administered by the BLM).

(4) To the extent existing grazing management practices or levels of grazing use on public lands are identified as significant causal factors preventing resources from achieving or making significant progress towards achieving land health standards, authorized officers must proceed under § 4180.2(c) of this chapter. by taking appropriate action as soon as practicable but no later than the start of the next grazing year.

(5) Taking appropriate action means implementing actions that will result in significant progress toward achieving land health standards. Appropriate action must be consistent with applicable law, regulation, and the governing land use plan and its management objectives, such as where an area is managed for recreation or is degraded land prioritized for development. Appropriate actions may include, but are not limited to:

(i) Establishment or modification of terms and conditions for permits, leases, and other use authorizations;

(ii) Development and implementation of activity plans;

(iii) Implementation of adaptive management actions; and

(iv) Control of unauthorized use.

(g) Upon determining that significant causal factors other than current management practices are preventing achievement of land health standards, but are not outside of BLM control (*e.g.,* presence of invasive species), the authorized officer shall identify and prioritize appropriate actions that may result in significant progress toward achievement of land health standards (*see* § 6102.5).

(h) Subject to other applicable law, authorized officers may implement restoration plans, modify authorized uses, or implement other management actions to increase expediency and effectiveness of progress towards achieving land health standards, to protect areas achieving land health standards, or to meet other objectives.

(i) If current authorized uses are determined to be significant causal factors and the authorized officer determines appropriate action is needed, then appropriate action must be consistent with the governing land use plan. Changes to some types of authorized uses may first warrant an amendment to the land use plan to allow the authorized officer to adjust those uses sufficient to make progress toward meeting land health standards. However, whether to undertake a planning process is at the discretion of the authorized officer.

(j) Authorized officers will report annually on land health evaluation, and determination accomplishments; results; and actions taken to address areas not achieving or making progress toward achieving standards.

(k) The BLM will maintain and annually update a publicly available record of land health evaluation and determination results and management actions taken to facilitate progress toward achieving land health standards.

§ 6103.2 Inventory, Assessment, and Monitoring.

(a) Watershed condition assessments must be completed at least once every 10 years and used to inform land use planning, protect intact landscapes (§ 6102.2), manage for ecosystem resilience (§ 6102.5), inform restoration actions (§ 6102.3), and inform land health evaluations and determinations (§ 6103.1.1). Watershed condition assessments assess and synthesize information on the condition of soil, water, habitats, and ecological processes within watersheds relative to the BLM's land health fundamentals and the national land health standards. When conducting watershed condition assessments, the BLM must:

(1) Compile and analyze multiple sources of high-quality information to understand conditions and trends relevant to each land health standard, including remote sensing products, field-based data, and other data gathered through inventory, assessment, and monitoring activities; and

(2) Incorporate consistent analytical approaches, quantitative indicators, and benchmarks where practicable.

(b) The BLM will maintain a publicly available inventory of infrastructure and natural resources on public lands. This inventory must include both critical landscape components (*e.g.,* roads, land types, streams, habitats) and core indicators that address land health fundamentals.

(c) Authorized officers will use high-quality inventory, assessment, and monitoring information, including standardized quantitative monitoring data, remote sensing maps, and geospatial analyses, to inform decision-making across program areas, including, but not limited to:

(1) Authorization of permitted uses;

(2) Land use planning;

(3) Watershed condition assessments and land health evaluations;

(4) Restoration planning, including prioritization;

(5) Assessments of restoration effectiveness;

(6) Consideration of areas of critical environmental concern;

(7) Evaluation and protection of intact landscapes;

(8) Restoration and mitigation leasing; and

(9) Other decision-making processes.

(d) Authorized officers must inventory, assess, and monitor activities as necessary to inform the decision-making processes identified in paragraph (b) of this section and, in so doing, must employ the following:

(1) Interdisciplinary monitoring plans for providing data relevant to decision makers;

(2) Standardized field protocols and indicators to allow data comparisons through space and time in support of multiple management decisions;

(3) Appropriate sample designs to minimize bias and maximize applicability of collected data;

(4) Integration with remote sensing products to optimize sampling and calibrate continuous map products; and

(5) Data management and stewardship to ensure data quality, accessibility, and use.

[FR Doc. 2024–08821 Filed 5–8–24; 8:45 am]

BILLING CODE 4331–27–P

FEDERAL REGISTER

Vol. 89 Thursday,
No. 91 May 9, 2024

Part VII

The President

Notice of May 8, 2024—Continuation of the National Emergency With Respect to Securing the Information and Communications Technology and Services Supply Chain
Notice of May 8, 2024—Continuation of the National Emergency With Respect to the Actions of the Government of Syria
Notice of May 8, 2024—Continuation of the National Emergency With Respect to the Central African Republic

Federal Register
Vol. 89, No. 91
Thursday, May 9, 2024

Presidential Documents

Title 3—

The President

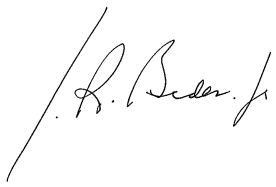
Notice of May 8, 2024

Continuation of the National Emergency With Respect to Securing the Information and Communications Technology and Services Supply Chain

On May 15, 2019, by Executive Order 13873, the President declared a national emergency pursuant to the International Emergency Economic Powers Act (50 U.S.C. 1701 *et seq.*) to deal with the unusual and extraordinary threat to the national security, foreign policy, and economy of the United States constituted by the unrestricted acquisition and use of certain information and communications technology and services transactions.

The unrestricted acquisition or use in the United States of information and communications technology or services designed, developed, manufactured, or supplied by persons owned by, controlled by, or subject to the jurisdiction or direction of foreign adversaries augments the ability of these foreign adversaries to create and exploit vulnerabilities in information and communications technology or services, with potentially catastrophic effects. This threat continues to pose an unusual and extraordinary threat to the national security, foreign policy, and economy of the United States. For this reason, the national emergency declared on May 15, 2019, must continue in effect beyond May 15, 2024. Therefore, in accordance with section 202(d) of the National Emergencies Act (50 U.S.C. 1622(d)), I am continuing for 1 year the national emergency declared in Executive Order 13873 with respect to securing the information and communications technology and services supply chain.

This notice shall be published in the *Federal Register* and transmitted to the Congress.



THE WHITE HOUSE,
May 8, 2024.

[FR Doc. 2024–10394
Filed 5–8–24; 2:00 pm]
Billing code 3395–F4–P

Presidential Documents

Notice of May 8, 2024

Continuation of the National Emergency With Respect to the Actions of the Government of Syria

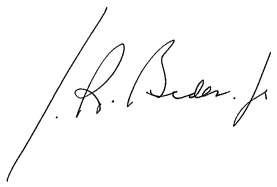
On May 11, 2004, pursuant to his authority under the International Emergency Economic Powers Act (50 U.S.C. 1701 *et seq.*) and the Syria Accountability and Lebanese Sovereignty Restoration Act of 2003 (Public Law 108–175), the President issued Executive Order 13338, in which he declared a national emergency with respect to the actions of the Government of Syria. The national emergency was modified in scope and relied upon for additional steps taken in Executive Order 13399 of April 25, 2006, Executive Order 13460 of February 13, 2008, Executive Order 13572 of April 29, 2011, Executive Order 13573 of May 18, 2011, Executive Order 13582 of August 17, 2011, Executive Order 13606 of April 22, 2012, and Executive Order 13608 of May 1, 2012.

The President took these actions to deal with the unusual and extraordinary threat to the national security, foreign policy, and economy of the United States constituted by the actions of the Government of Syria in supporting terrorism, maintaining its then-existing occupation of Lebanon, pursuing weapons of mass destruction and missile programs, and undermining United States and international efforts with respect to the stabilization and reconstruction of Iraq.

The regime's brutality and repression of the Syrian people, who have called for freedom and a representative government, not only endangers the Syrian people themselves, but also generates instability throughout the region. The Syrian regime's actions and policies, including with respect to chemical weapons and supporting terrorist organizations, continue to pose an unusual and extraordinary threat to the national security, foreign policy, and economy of the United States. As a result, the national emergency declared in Executive Order 13338, which was expanded in scope in Executive Order 13572, and with respect to which additional steps were taken in Executive Order 13399, Executive Order 13460, Executive Order 13573, Executive Order 13582, Executive Order 13606, and Executive Order 13608, must continue in effect beyond May 11, 2024. Therefore, in accordance with section 202(d) of the National Emergencies Act (50 U.S.C. 1622(d)), I am continuing for 1 year the national emergency declared with respect to the actions of the Government of Syria.

In addition, the United States condemns the brutal violence and human rights violations and abuses of the Assad regime and its Russian and Iranian enablers. The United States calls on the Assad regime, and its backers, to stop its violent war against its own people, enact a nationwide ceasefire, facilitate the unhindered delivery of humanitarian assistance to all Syrians in need, and negotiate a political settlement in Syria in line with United Nations Security Council Resolution 2254. The United States will consider changes in policies and actions of the Government of Syria in determining whether to continue or terminate this national emergency in the future.

This notice shall be published in the *Federal Register* and transmitted to the Congress.



THE WHITE HOUSE,
May 8, 2024.

[FR Doc. 2024–10400
Filed 5–8–24; 2:00 pm]
Billing code 3395–F4–P

Presidential Documents

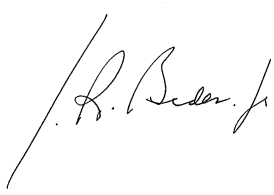
Notice of May 8, 2024

Continuation of the National Emergency With Respect to the Central African Republic

On May 12, 2014, by Executive Order 13667, the President declared a national emergency pursuant to the International Emergency Economic Powers Act (50 U.S.C. 1701–1706) to deal with the unusual and extraordinary threat to the national security and foreign policy of the United States constituted by the situation in and in relation to the Central African Republic, which has been marked by a breakdown of law and order; intersectarian tension; the pervasive, often forced recruitment and use of child soldiers; and widespread violence and atrocities, including those committed by Kremlin-linked and Yevgeniy Prigozhin–affiliated entities such as the Wagner Group, and which threatens the peace, security, or stability of the Central African Republic and neighboring states.

The situation in and in relation to the Central African Republic continues to pose an unusual and extraordinary threat to the national security and foreign policy of the United States. For this reason, the national emergency declared in Executive Order 13667 on May 12, 2014, to deal with that threat must continue in effect beyond May 12, 2024. Therefore, in accordance with section 202(d) of the National Emergencies Act (50 U.S.C. 1622(d)), I am continuing for 1 year the national emergency declared with respect to the Central African Republic.

This notice shall be published in the *Federal Register* and transmitted to the Congress.



THE WHITE HOUSE,

May 8, 2024.

[FR Doc. 2024–10403

Filed 5–8–24; 2:00 pm]

Billing code 3395–F4–P

Reader Aids

Federal Register

Vol. 89, No. 91

Thursday, May 9, 2024

CUSTOMER SERVICE AND INFORMATION

Federal Register/Code of Federal Regulations	
General Information, indexes and other finding aids	**202–741–6000**
Laws	**741–6000**
Presidential Documents	
Executive orders and proclamations	**741–6000**
The United States Government Manual	**741–6000**
Other Services	
Electronic and on-line services (voice)	**741–6020**
Privacy Act Compilation	**741–6050**

ELECTRONIC RESEARCH

World Wide Web

Full text of the daily Federal Register, CFR and other publications is located at: **www.govinfo.gov.**

Federal Register information and research tools, including Public Inspection List and electronic text are located at: **www.federalregister.gov.**

E-mail

FEDREGTOC (Daily Federal Register Table of Contents Electronic Mailing List) is an open e-mail service that provides subscribers with a digital form of the Federal Register Table of Contents. The digital form of the Federal Register Table of Contents includes HTML and PDF links to the full text of each document.

To join or leave, go to **https://public.govdelivery.com/accounts/USGPOOFR/subscriber/new**, enter your email address, then follow the instructions to join, leave, or manage your subscription.

PENS (Public Law Electronic Notification Service) is an e-mail service that notifies subscribers of recently enacted laws.

To subscribe, go to **http://listserv.gsa.gov/archives/publaws-l.html and select** *Join or leave the list (or change settings);* then follow the instructions.

FEDREGTOC and **PENS** are mailing lists only. We cannot respond to specific inquiries.

Reference questions. Send questions and comments about the Federal Register system to: **fedreg.info@nara.gov**

The Federal Register staff cannot interpret specific documents or regulations.

FEDERAL REGISTER PAGES AND DATE, MAY

34945–35684	1
35685–36650	2
36651–37058	3
37059–37964	6
37965–38836	7
38837–39530	8
39531–40358	9

CFR PARTS AFFECTED DURING MAY

At the end of each month the Office of the Federal Register publishes separately a List of CFR Sections Affected (LSA), which lists parts and sections affected by documents published since the revision date of each title.

2 CFR

XVI 34953

3 CFR

Proclamations:

10733 34945
10734 34949
10735 36651
10736 36655
10737 36657
10738 36659
10739 36661
10740 36663
10741 36665
10742 36667
10743 36669
10744 37059
10745 39531

Administrative Orders:

Notices:
Notice of May 8, 2024 40353
Notice of May 8, 2024 40355
Notice of May 8, 2024 40357

5 CFR

890 37061

Proposed Rules:

532 36720

6 CFR

Proposed Rules:

26 37141

7 CFR

354 38596
981 37965
1430 39539
1719 34955
1738 34955
1739 34955
1774 34955
1775 34955
1780 subpart A 34959
1940 subpart L 34959
3570 34955
4274 34955
4279 34955
4280 34955
4288 34955

9 CFR

11 39194
71 39540
77 39540
78 39540
86 39540

10 CFR

Ch. III 37079
429 37778
430 ..... 37778, 37987
433 35384
435 35384
900 35312

Proposed Rules:

430 38762

11 CFR

4 35685

12 CFR

1610 37091

13 CFR

120 35688

14 CFR

25 39566
29 37969
34 37971
39 ..... 34961, 34982, 34986, 34988, 35690, 35693, 35695, 35698, 35701, 37109, 37111

Proposed Rules:

25 38004
39 ..... 35015, 37142, 37144, 38841, 38846
71 ..... 35018, 35019, 35021, 35022, 35024, 35025, 35027
382 38852

15 CFR

326 37972
738 38837

16 CFR

910 38342
912 38342

17 CFR

23 34991
37 34991

18 CFR

Proposed Rules:

2 37147
38 37147

20 CFR

655 38838

21 CFR

112 37448
809 37286

Proposed Rules:

809 37158

22 CFR

Proposed Rules:

126 35028

23 CFR

490 37113

1300.....37113

24 CFR

5.....38224
8.....38224
42.....38224
50.....38224
91.....38224
92.....38224
93.....38224
247.....38224
290.....38224
882.....38224
888.....38224
891.....38224
903.....38224
908.....38224
943.....38224
945.....38224
960.....38224
972.....38224
982.....38224
983.....38224
985.....38224
1000.....38224

26 CFR

1.....37706
26.....37116
301.....37116, 37706
602.....37116

Proposed Rules:

1.....39440

28 CFR

106 .....36671, 36673, 36675

31 CFR

591.....35703

Proposed Rules:

100.....36721

32 CFR

310.....37127
1665.....35004

Proposed Rules:

776.....36723

33 CFR

100 .....35006, 35705, 35708, 37130
117.....37974
147.....35709, 37130
165 .....35712, 35714, 36671, 37134, 38839

Proposed Rules:

110.....38853, 38854
165 .....35767, 38854, 38857, 39576

36 CFR

219.....37135
1225.....35007

37 CFR

1.....36677

39 CFR

111.....35716

40 CFR

9.....38950
52.....36679, 37137
60.....39304, 39798
63.....38508, 39304
131.....35717
228.....36681
257.....38950
268.....35008
302.....39124
372.....35748
423.....40198
702.....37028
751.....39254
1500.....35442
1501.....35442
1502.....35442
1503.....35442
1504.....35442
1505.....35442
1506.....35442
1507.....35442
1508.....35442

Proposed Rules:

51.....36870
52.....36729, 36870
180.....36737

41 CFR

300–3.....37975
302–6.....37975
302–7.....37975

42 CFR

435.....39392
438.....37522
440.....37522
457.....37522, 39392
460.....37522
600.....39392

Proposed Rules:

412.....35934
413.....35934
431.....35934
482.....35934
485.....35934
495.....35934
512.....35934

43 CFR

1600.....40308
2360.....38712
2800.....35634
6100.....40308

45 CFR

75.....36684
80.....37522
84.....37522, 40066
92.....37522
147.....37522
152.....39392
155.....37522, 39392
156.....37522
1324.....39488

46 CFR

541.....39561

47 CFR

73.....36705, 36718

Proposed Rules:

76.....38007

48 CFR

727.....37948
742.....37948
752.....37948
1602.....37061
1609.....37061

Proposed Rules:

40.....36738

49 CFR

24.....36908
171.....39570
172.....39570
173.....39570
175.....39570
176.....39570
178.....39570
180.....39570
571.....39686
595.....39686
596.....39686
1145.....38646
1500.....35580
1503.....35580
1515.....35580
1540.....35580
1542.....35580
1544.....35580
1546.....35580
1548.....35580
1549.....35580
1550.....35580
1552.....35580
1554.....35580
1570.....35580
1572.....35580

Proposed Rules:

385.....36742

50 CFR

17.....36982
92.....35010
622.....35011
635.....37139
648.....35755
660.....35012
665.....37984, 37985
679.....35013, 39575

Proposed Rules:

216.....35769

LIST OF PUBLIC LAWS

This is a continuing list of public bills from the current session of Congress which have become Federal laws. This list is also available online at *https://www.archives.gov/federal-register/laws/current.html*.

The text of laws is not published in the **Federal Register** but may be ordered in ''slip law'' (individual pamphlet) form from the Superintendent of Documents, U.S. Government Publishing Office, Washington, DC 20402 (phone, 202–512–1808). The text is available at *https://www.govinfo.gov/app/collection/plaw*. Some laws may not yet be available.

H.R. 292/P.L. 118–52

To designate the facility of the United States Postal Service located at 24355 Creekside Road in Santa Clarita, California, as the ''William L. Reynolds Post Office Building''. (May 7, 2024)

H.R. 996/P.L. 118–53

To designate the facility of the United States Postal Service located at 3901 MacArthur Blvd., in New Orleans, Louisiana, as the ''Dr. Rudy Lombard Post Office''. (May 7, 2024)

H.R. 2379/P.L. 118–54

To designate the facility of the United States Postal Service located at 616 East Main Street in St. Charles, Illinois, as the ''Veterans of the Vietnam War Memorial Post Office''. (May 7, 2024)

H.R. 2754/P.L. 118–55

To designate the facility of the United States Postal Service located at 2395 East Del Mar Boulevard in Laredo, Texas, as the ''Lance Corporal David Lee Espinoza, Lance Corporal Juan Rodrigo Rodriguez & Sergeant Roberto Arizola Jr. Post Office Building''. (May 7, 2024)

H.R. 3865/P.L. 118–56

To designate the facility of the United States Postal Service located at 101 South 8th Street in Lebanon, Pennsylvania, as the ''Lieutenant William D. Lebo Post Office Building''. (May 7, 2024)

H.R. 3944/P.L. 118–57

To designate the facility of the United States Postal Service located at 120 West Church Street in Mount Vernon, Georgia, as the ''Second Lieutenant Patrick Palmer Calhoun Post Office''. (May 7, 2024)

H.R. 3947/P.L. 118–58

To designate the facility of the United States Postal Service located at 859 North State Road 21 in Melrose, Florida, as the ''Pamela Jane Rock Post Office Building''. (May 7, 2024)

S. 474/P.L. 118–59

Revising Existing Procedures On Reporting via Technology Act (May 7, 2024)

Last List April 26, 2024

Public Laws Electronic Notification Service (PENS)

PENS is a free email notification service of newly enacted public laws. To subscribe, go to *https://portalguard.gsa.gov/__*layouts/pg/register.aspx.

Note: This service is strictly for email notification of new laws. The text of laws is not available through this service. **PENS** cannot respond to specific inquiries sent to this address.